BOOK IV

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS STATEMENT NO. 8 – DAVID E. LAHOFF
UGI GAS STATEMENT NO. 9 – SHAUN M. HART
UGI GAS STATEMENT NO. 10 – DANIEL V. ADAMO
UGI GAS STATEMENT NO. 11 – NICOLE M. McKINNEY
UGI GAS STATEMENT NO. 12 – ANGELINA M. BORELLI
UGI GAS STATEMENT NO. 13 – THEODORE M. LOVE

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

DOCKET NO. R-2018-3006814

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

UGI GAS STATEMENT NO. 8 – DAVID E. LAHOFF

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3006814

UGI Utilities, Inc. – Gas Division

Statement No. 8

Direct Testimony of
David E. Lahoff

Topics Addressed:	**Test Years Sales/Revenues** **Uniform Rate Structure and Riders** **Tax Cut and Jobs Act Credit** **Revenue Allocation and Rate Design** **GET Gas** **Tariff Changes** **Purchase of Receivables Program**

Dated: January 28, 2019

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David E. Lahoff. My current business address is 1 UGI Drive, Denver, Pennsylvania, 17517

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

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

Q. Please briefly describe your responsibilities in that capacity.

A. My current responsibilities include: (1) all aspects of tariff and rate administration for UGI, including interactions with natural gas suppliers and electric generation suppliers for both UGI Utilities, Inc. – Gas Division ("UGI Gas" or "Company") and UGI Utilities, Inc. – Electric Division ("UGI Electric"); (2) revenue planning; and (3) oversight of UGI's energy management system. As a result of the recent Commission-approved merger described by other witnesses in this proceeding, UGI Gas currently operates three rate districts – UGI North, which encompasses the service territory of UGI Gas's former subsidiary, UGI Penn Natural Gas, Inc. ("UGI PNG"); UGI Central, which encompasses the service territory of UGI Gas's former subsidiary UGI Central Penn Gas, Inc. ("UGI CPG"); and UGI South, which encompasses the former service territory of UGI Gas before the merger.

Q. Please provide your educational background.

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

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

A. Yes, I have testified in the following dockets: UGI CPG 2009 Base Rate Case, Docket No. R-2008-2079675; UGI PNG 2009 Base Rate Case, Docket No. R-2008-2079660; UGI Gas 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; UGI PNG Gas Procurement Charge Filing, Docket No. R-2012-2314224; UGI CPG Gas Procurement Charge Filing, Docket No. R-2012-2314247; UGI Gas, UGI PNG and UGI CPG Growth Extension Tariff ("GET Gas") Filing, Docket No. P-2013-2356232; UGI - Electric Division Default Service Filing, Docket No. P-2013-2357013; UGI Gas 2016 Base Rate Case, Docket No. R-2015-2518438; UGI PNG Base Rate case, Docket R-2016-2580030; and UGI - Electric Division 2018 Base Rate Case, Docket No. R-2017-2640058.

Q. Please describe the purpose of your testimony.

A. I will address: (1) the development of annualized and normalized sales and revenues, including use-per-customer adjustments due to energy savings from the proposed consolidated Energy Efficiency and Conservation ("EE&C") Plan, for the historic test year ended September 30, 2018 ("HTY"), the future test year ending September 30, 2019 ("FTY"), and the fully projected future test year ending September 30, 2020 ("FPFTY"); (2) UGI Gas's proposed consolidated rate structure, including the establishment of a uniform Purchased Gas Cost ("PGC") rate; (3) revenue allocation and rate design; (4) the GET Gas Pilot Program surcharge; (5) other proposed tariff modifications; (6) an update to the proposed expansion of UGI Gas's purchase of receivables ("POR") program and (7) the treatment of the credit associated with the Tax Cut and Jobs Act ("TCJA") for the period of January 2018 through June 2018.

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 (Normalized multi-year and Normalized 12 month ending trends of use per customer for the residential heating and commercial heating customer groups); 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 unified EE&C Rider); UGI Gas Exhibit DEL-8 (calculation of unified USP Rider); UGI Gas Exhibit DEL-9 (unified Rate NNS calculation); UGI Gas Exhibit DEL-10 (unified Rate MBS calculation); UGI Gas Exhibit DEL-11 (calculation of unified GPC); UGI Gas Exhibit DEL-12 (calculation of unified MFC percentages); UGI Gas Exhibit DEL-13 (calculation of GET Gas revenues) and Schedule D-5A of UGI Gas Exhibit A. I am also sponsoring those schedules that were prepared by me or under my direction. Specifically, I am sponsoring certain responses to the Commission's standard filing requirements as indicated on the master list accompanying this filing.

II. SALES AND REVENUES

A. Development of FPFTY Sales and Revenues

Q. How is the presentation of FPFTY sales and revenues in this proceeding influenced by UGI Gas's recent merger proceeding?

A. In UGI Gas's recent merger proceeding at Docket Nos. A-2018-3000381, A-2018-3000382 and A-2018-3000383, UGI Gas agreed to the following terms in its Commission-approved settlement:

> *7. In its first base rate case post-merger, UGI Gas Division will file separate revenue requirement models and cost allocation studies on a consistent basis for each rate district, and will be permitted to file a consolidated revenue requirement model and class cost of service study, which will be subject to the following requirements:*
>
> *(a) UGI will submit detailed sales and revenue schedules for each rate class within each rate district that show the following: (1) actual historic year sales and revenues; (2) adjusted historic year sales and revenues along with specific historic year ratemaking adjustments individually identified as to amount and purpose (adjusted historic year); (3) future year budgeted sales and revenues along with specific ratemaking adjustments individually identified as to amount and purpose (adjusted future year); and, (4) fully projected future year ("FPFTY") budgeted sales and revenues along with specific FPFTY ratemaking adjustments individually identified as to amount and purpose (adjusted FPFTY).*

UGI Gas's filing is based on a consolidated revenue requirement model (UGI Gas Exhibit A – Fully Projected) and consolidated cost of service study (UGI Gas Exhibit D). In addition, and consistent with the merger proceeding settlement, the Company is also providing, for informational purposes only, separate revenue requirement models (UGI Gas Exhibit G) and separate class cost of service studies (UGI Gas Exhibit H) for each of its three existing rate districts.

Q. Why is the Company utilizing a combined revenue requirement model and class cost of service study?

A. The former natural gas distribution subsidiaries of UGI have merged into UGI Gas, forming a unified corporate structure that is reflective of how they have been managed on a unified basis for some time. For the reasons more fully explained in the testimony of UGI Gas witness Paul J. Szykman (UGI Gas St. No. 1), the Company believes there are many benefits that can now be achieved for customers, the Company, natural gas suppliers ("NGSs"), the Commission and the public parties from adopting uniform rates and a unified tariff. As such, the Company is proposing such unified rates and tariff rules in this proceeding, consistent with its authorization to do so in its recent Commission-approved merger proceeding. Thus, the revenue requirement for the Company (UGI Gas Exhibit A) has been established on a unified basis. Similarly, our class cost of service study for the FPFTY (UGI Gas Exhibit D) has also been performed on a total Company basis and assigns total Company cost of service to rate classes. The currently effective individual rates of each district are legacy rates based on pre-merger conditions, and are not based on total Company post-merger cost of service or allocated cost of service. To address any concerns regarding rate gradualism, UGI Gas is proposing a revenue allocation that moves its major rate classes substantially towards cost of service, but not all of the way to full cost of service. I discuss specific revenue allocation impacts and the Company's consideration of gradualism later in my testimony.

Q. Please explain the process for developing the Company's fiscal year 2020 sales and revenue budgets.

A. The sales and revenue budgets were a joint effort of the marketing and financial planning and analysis departments, with the marketing department providing customer growth and attrition information by customer class along with specific large commercial and industrial sales and revenue budget projections. The financial planning and analysis department developed projections for budgeted usage per customer for core customer classes, total calculated sales and total calculated revenues. 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 2020 budget was the same as that used for the 2019 budget and did not incorporate use per customer trends. Normalized budget use per customer values were developed based on a simple regression of 24 months of actual use per customer data against actual heating degree data. 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 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 2020 planned budgets reflects a preliminary forecast that will be subsequently updated during 2019 as part of the normal annual 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 adjustments to budget values is the same for all three periods and was performed in order to present sales and revenue on a ratemaking basis, as I noted earlier.

Q. Please explain how the Company's FPFTY sales and revenues were developed on a consolidated basis.

A. FPFTY sales and revenues were developed on a consolidated basis by annualizing and normalizing the Company's 2020 fiscal year planned sales and revenue budgets. The projected Residential Heating use per customer was established on a combined total basis for Rate R/RT-Heating per the UGI Gas model detailed in SDR-RR-11. Since, over time, switching among these mass market residential classes occurs on a regular basis between Rates R (retail service) and RT (transportation service), the regression analysis was performed on a total Rate R/RT basis in order to eliminate potential switching impacts which could distort use per customer analyses. I provide more detail on this regression analysis below where I discuss the Company's "Adjustment for Normalized &

Annualized Use/Customer." Weather normalized sales for Rate RT-Heating customers were then utilized to derive the separate Rate RT-Heating and Rate R-Heating use per customer values from the combined Rate R/RT use per customer value.

Combined actual sales were normalized for Rate R-General and Rate RT-General in order to project combined Rate R/RT-General use per customer in total. Weather normalized sales for Rate RT-General were then utilized to derive the separate Rate RT-General and Rate R-General customer values from the combined Rate R/RT-General use per customer value.

The projected Commercial Heating use per customer was established on a combined total basis for Rates N/NT/DS-Heating per the UGI Gas model regression techniques detailed in SDR-RR-11. Given that, over time, switching among these mass market smaller classes occurs on a regular basis between Rates N (retail service), NT (transportation service) and DS (transportation service), the regression analysis was performed on a total Rate N/NT/DS basis in order to eliminate potential switching impacts which could distort use per customer analyses. I provide more detail on this regression below where I discuss the Company's "Adjustment for Normalized & Annualized Use/Customer." Weather normalized sales for Rate NT-Commercial Heating customers and budgeted sales for Rate DS-Commercial Heating were then utilized to derive the separate Rate NT-Commercial Heating, Rate N-Commercial Heating and Rate DS-Commercial Heating use per customer values from the combined Rate N/NT/DS-Commercial Heating use per customer value.

Combined actual sales were normalized for Rate N-Commercial General, Rate NT-Commercial General and Rate DS-Commercial General in order to project combined

Rate N/NT/DS-Commercial General use per customer in total. Weather normalized sales for Rate NT-Commercial General and budgeted sales for Rate DS-Commercial General were then utilized to derive the separate Rate NT-Commercial General, Rate N-Commercial General and Rate DS-Commercial General use per customer values from the combined Rate N/NT/DS-Commercial General use per customer value.

Combined actual sales were normalized for Rate N-Industrial, Rate NT-Industrial and Rate DS-Industrial in order to project combined Rate N/NT/DS-Industrial use per customer in total. Weather normalized sales for Rate NT-Industrial and budgeted sales for Rate DS-Industrial were then utilized to derive the separate Rate NT-Industrial, Rate N-Industrial and Rate DS-Industrial use per customer values from the combined Rate N/NT/DS-Industrial use per customer value.

Q. How was temperature accounted for in developing sales and revenue forecasts?

A. The Company's FPFTY sales and revenue forecasts reflect annual normal heating degree days of 5,687 on a consolidated basis, reflecting the composite sales weighted value of each rate district's specific annual normal heating degree days of 6,019, 6,297, and 5,214 for UGI Gas's North, Central and South Rate Districts, respectively. Normal heating degree days by rate district were based upon an average over a fifteen-year period. Normal heating degree day values are updated every five years. The most recent five-year update for the rate districts occurred on December 31, 2014. UGI Gas Exhibit DEL-1 provides the supporting calculation of the annual normal degree days utilized on a consolidated basis.

Q. Is the use of average temperature data for a fifteen-year period consistent with the methodology used for calculating normal heating degree days in the previous base rate cases of UGI Gas's rate districts?

A. Yes. UGI Gas's South Rate District used a fifteen-year period to develop normal heating degree days in its 2016 base rate case. UGI Gas's Central Rate District used this methodology in its 2009 and 2011 base rate cases, and UGI Gas's North Rate District used this methodology in its 2009 and 2017 base rate cases.

Q. Please describe the detailed adjustments made to the planned budget for the twelve months ending September 30, 2020 to develop FPFTY sales and revenues

A. A summary of all adjustments made to the 2020 planned budget in order to develop FPFTY sales is shown on UGI Gas Exhibit DEL-3(a). In total, these adjustments reflect a decrease to sales of 2,757 MMcf and a decrease to revenue of $78,650 million, inclusive of PGC revenues, on a consolidated basis.

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 on a consolidated and individual rate district level. In particular, this adjustment includes a net decrease of 1,101 residential heating customers from budgeted levels to anticipated end-of-test-year levels and a net increase of 72 non-residential heating customers from budgeted levels to anticipated end-of-FPFTY levels on a consolidated basis.

Q. How were these adjustments quantified?

A. UGI Gas Exhibit DEL-3(b) provides the calculation of the associated sales and revenue adjustments for the stated customer counts. In total, as reflected on UGI Gas Exhibit DEL-3(a), this adjustment decreases sales by 271 MMcf and decreases projected revenues by $2.033 million, inclusive of PGC revenues. Additional detail for column (9) of UGI Gas Exhibit DEL-3(b) can be found on UGI Gas Exhibit DEL-3(b)(1), which provides a breakout of customer data for large transportation customer classes.

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

A. The "Adjustment for Normalized & Annualized Use/Customer" normalizes and annualizes Residential Heating and Commercial Heating usage per customer to projected end-of-test-year levels based on a multi-year regression analysis of actual usage and degree day information. Specifically, in developing usage per customer projections for the Residential Heating rate groups, the Company utilized an econometric regression model that incorporates four independent variables: (1) use per customer; (2) heating degree days; (3) lagged heating degree days; and (4) weighted time trend. While use per customer and heating degree days capture weather related usage factors, which can then be used to project normalized and annualized customer usage under normal weather conditions, the time trend variable of this regression captures non-weather trends that underlie changes in usage per customer over time, such as conservation. These trends can be varied, but as a comprehensive variable, "trend" will capture the impacts of conservation, 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, a trend variable is used to provide a comprehensive indicator of usage trends, which can then be used to forecast for a future period. Additionally, the trend variable is weighted by heating degree days to reflect a "weighted trend" which more accurately reflects that the impacts of these trends are directly related to usage during heating time periods.

For Commercial Heating rate groups, the Company evaluated, but excluded, the weighted trend variable as it did not demonstrate statistical significance. Instead, to forecast the Commercial Heating rate group use per customer, the Company utilized three variables: (1) use per customer; (2) heating degree days; and (3) lagged heating degree days.

For the Residential Heating groups of Rates R and RT, the multi-year period regression methodology is the same method the Company utilized in prior UGI Gas rate district base rate cases, updated for the use of a common data set period of October 2003 through September 2018, as October 2003 is the earliest data available for both the UGI Gas North and UGI Gas Central Rate Districts.

For the Commercial Heating groups of Rates N, NT and DS, the Company used the period of October 2012 through September 2018, when a common rate structure existed for the three rate districts. Specifically, in the 2011 UGI Gas Central Rate

District base rate case, legacy commercial and industrial tariff rates and rate structures (those originally of PPL Gas, pre-UGI acquisition) were translated to common tariff rates for the UGI Gas South Rate District and for UGI Gas North Rate District, *i.e.*, Rate N, NT, DS, LFD and XD. While new base rates were effective late in 2011, the Company began the regression period with October 2012 data in order to avoid possible impacts of customer rate migration over the one-year period following the initial translation to the new rate structures.

The forecasts for end-of-FPFTY use per customer are generated using the regression results along with a projection of regression variable inputs including normal annual heating degree days and, where applicable, a weighted trend variable. The results are presented in summary on UGI Gas Exhibit DEL-3(a) and in detail on UGI Gas Exhibit DEL-3(c). In total, the result is a net sales decrease, from fiscal 2020 budget, of 2,286 MMcf, and a net revenue decrease, from fiscal 2020 budget, of $22,703,000, inclusive of PGC revenues. Additional detail for column (9) of UGI Gas Exhibit DEL-3(c) can be found on UGI Gas Exhibit DEL-3(c)(1), which provides a breakout of customer data for large transportation customer classes.

Q. Why did UGI Gas utilize a multi-year regression period?

A. The Company decided to use the multi-year period because it provides a larger sample set of data to smooth out short-term variations and capture the underlying long-term use per customer trends in order to more accurately project usage per customer during the period rates are likely to be in effect. This methodology is consistent with that utilized in the last five base rate cases of UGI Gas's rate districts. Regression input values, where appropriate, reflect a weighted average value of the three rate district data sets.

Q. Has UGI Gas compared the results of the multi-year regression method to develop normalized usage for Residential Heating and Commercial Heating customer groups with any other normalization method?

A. Yes. Please see UGI Gas Exhibits DEL-2(a) and DEL-2(b), which contain use per customer graphs that illustrate both the results of the multi-year normalized regression method I have explained above ("Normalized Multi-year") and a short- term normalized ("Normalized 12 Months ended") value for the same groups of Residential Heating and Commercial Heating customers. The short-term normalized values are computed via a simple determination of temperature sensitive load each month on a consolidated basis. As can be seen from these graphs, short-term trend fluctuations of the "Normalized 12 months ended" line occur in certain periods, but consistently revert to the long-term "Normalized Multi-year" trend which has been used to forecast FPFTY use per customer values. This provides clear support for the use of the multi-year regression method.

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

A. Yes. As part of this rate filing, the Company is proposing to implement a unified and expanded EE&C Plan. The energy savings associated with the EE&C Plan will primarily occur in the residential and small commercial customer rate classes. UGI Gas Exhibit DEL-3(l) shows the summary energy savings for Rates R/RT and N/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/RT is a decrease of 0.3 Mcf, the incremental impact on use per customer for Rates N/NT is a decrease of 0.6 Mcf. These reductions are included in the calculation of adjusted use per customer for the FPFTY. Given the much smaller impacts, no adjustments for energy savings were made for rate classes DS and LFD. The buildup for the overall energy savings is addressed in the direct testimony of Theodore M. Love (UGI Gas St. No. 13). This adjustment decreases total sales by 201 MMcf and reduces revenue by $1.49 million for the FPFTY, inclusive of PGC revenue.

Q. Please explain the adjustments titled "Adjustment for Customer Changes – Large Transport and Interruptible Detail" and "Adjustment for Annualized Usage and Annualized Rates – Large Transport and Interruptible Detail," as shown on UGI Gas Exhibit DEL-3(b)(1) and UGI Gas Exhibit DEL-3(c)(1).

A. These adjustments for large transportation customers were developed by UGI Gas marketing personnel following their review of individual large customer accounts and market segments. It reflects annualizing anticipated increases or reductions from original fiscal year 2020 budget levels in the sales and revenues for these accounts.

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) annualizes FPFTY PGC revenues using the PGC rate in effect as of December 1, 2018 on a consolidated basis. UGI Gas Exhibit DEL-3(d) provides the calculations for these adjustments. This adjustment decreases PGC revenues for the FPFTY by $39 million on a consolidated basis.

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

A. The Adjustment for MFC annualizes the Company's Merchant Function Charge ("MFC") revenues for the FPFTY based on the MFC surcharge rates in effect as of December 1, 2018 on a consolidated basis. The Adjustment for USP annualizes the Company's Universal Service Program ("USP") surcharge revenues for the FPFTY based on the USP Rider rate in effect as of December 1, 2018 on a consolidated basis. The Adjustment for GPC annualizes the Gas Procurement Cost ("GPC") revenues to reflect the volume variance to the original fiscal year 2020 planned budget on a consolidated basis. The MFC Adjustment decreases projected revenues by $644,000 on a consolidated basis. The USP adjustment decreases revenues by $2.3 million on a consolidated basis. The GPC adjustment decreases revenues by $220,000 on a consolidated basis. Additional details for these three adjustments are provided on UGI Gas Exhibit DEL-3(e), UGI Gas Exhibit DEL-3(f) and UGI Gas Exhibit DEL-3(g), respectively.

Q. Please explain the "Adjustment for Interruptible."

A. The "Adjustment for Interruptible" annualizes the Company's interruptible revenues for the FPFTY at the current budgeted level of revenue less 20% to fund an Extension and Expansion Fund ("EEF") as well as an additional 20% as a revenue sharing mechanism to incent the Company to maximize interruptible revenues. The adjustments and program proposals are discussed in greater detail by Paul J. Szykman (UGI Gas St. No. 1) and Shaun M. Hart (UGI Gas St. No. 9). In total, the Interruptible Adjustment decreases revenues by $9.4 million on a consolidated basis.

Q. Please explain "Adjustment for Excess Take Revenues" as shown on UGI Gas Exhibit DEL-3(i).

A. The "Adjustment for Excess Take" detailed in UGI Gas Exhibit DEL-3(i), reflects the assumption that large transportation 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 $1.7 million.

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

A. The "Adjustment for STAS" annualizes the revenue from the UGI Gas State Tax Adjustment Surcharges ("STAS") based on a consolidated weighted average of the current rate district levels. This STAS adjustment increases projected revenues by $15,000 on a consolidated basis.

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

A. The "Adjustment for EEC Rider" annualizes the revenue based on a consolidated weighted average of the current rate district levels. This adjustment increases revenues by $823,000 on a consolidated basis.

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

A. The "Adjustment for GET Gas" annualizes GET Gas revenues to reflect end of year conditions. The revised revenues were developed by annualizing the projected GET Gas surcharge payments for the month of September 2020. This adjustment increases revenues by $32,000 on a consolidated basis.

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

A. The "Adjustment for DSIC Revenues**"** annualizes the revenue based on a consolidated weighted average of the current rate district levels. This adjustment decreases revenues by $6.7 million on a consolidated basis.

Q. Please explain the "Adjustment for TCJA" on UGI Gas Exhibit DEL-3(o).

A. The "Adjustment for TCJA**"** annualizes the revenue based on a consolidated weighted average of the current rate district levels. This adjustment increases revenues by $6.5 million.

Q. Please explain the "Adjustment for GDE" on UGI Gas Exhibit DEL-3(p).

A. The "Adjustment for GDE**"** annualizes Rider Gas Delivery Enhancement ("GDE") revenue based on current rate district rates as compared to the budgeted rate district revenues. This adjustment increases revenues by $189,000 on a consolidated basis.

Q. Do the adjusted FPFTY revenues exclude revenues related to off-system sales and non-jurisdictional revenue?

A. Yes.

Q. Do the FPFTY revenues include revenues currently recovered through the Company's Distribution System Improvement Charge ("DSIC") mechanism?

A. While FPFTY present rate revenues include DSIC charge revenues, FPFTY revenues at proposed rates eliminate DSIC revenues because the DSIC mechanism will be re-set to zero, except to accomplish reconciliation of prior costs and recoveries pursuant to Commission rules and the Company's tariff, upon the effective date of new base rates established in this proceeding. Qualifying DSIC investments currently recovered through the DSIC will be subsequently recovered via base rates. UGI Gas Exhibit E, Proof of Revenue, presents DSIC present rate revenues and the proposed zeroing out of the DSIC charge at proposed rates.

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

Q. How were normalized and annualized sales and revenue determined for the FTY?

A. Budgeted sales and revenues serve as the starting point for the development of the normalized and annualized FTY sales and revenues shown in UGI Gas Exhibit DEL-4(a) on a combined basis. All of the adjustments that were made in the development of the FPFTY were also made in the development of the FTY, with the exception of the adjustment for the EEC Conservation Impact that is contained in the FPFTY, but not the FTY.

Q. How were normalized and annualized sales and revenue determined for the HTY?

A. Historic sales and revenues serve as the starting point for the development of the normalized and annualized HTY sales and revenues shown in UGI Gas Exhibit DEL-5(a). All of the adjustments that were made in the development of the FPFTY were also made in the development of the HTY, with the exception of the adjustments for the EEC Rider, the EEC Conservation Impact, the TCJA adjustment and the GDE adjustment.

III. UNIFORM RATE STRUCTURE AND RIDERS

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

A. In general, the Company is preserving the existing rate structure. The current rate structure established in prior rate district rate proceedings includes Rates R, RT, N, NT, DS, LFD, XD and IS. The major change, discussed in detail below, is to propose unified rates and riders for the three former rate districts. This includes base rates and PGC rates and various other riders and rules, including: (1) Rate NNS (No Notice Service) and Rate MBS (Monthly Balancing Service); (2) new daily balancing tolerances and modified cash-in cash-out rules are proposed in this proceeding in order to unify Choice and Non-Choice Transportation rules, as discussed by Angelina M. Borelli (UGI Gas St. No. 12); (3) expanding the availability of the Technology and Economic Development ("TED") Rider, previously approved in earlier base rate cases for the UGI Gas North and South Rate Districts, to include the UGI Gas Central Rate District, as discussed by Shaun M.. Hart (UGI Gas St. No. 9); and (4) expanding the Company's EE&C program, previously approved in base rate cases for the UGI Gas North and South Rate Districts, to include the UGI Gas Central Rate District as discussed by Shaun M. Hart (UGI Gas St. No. 9).

Q. What is the Company proposing regarding the DSIC rate?

A. UGI Gas is proposing to establish a single system-wide DSIC to recover the costs incurred under its Commission-approved Long-Term Infrastructure Improvement Plans ("LTIIP"). As described by Hans G. Bell (UGI Gas Statement No. 2), UGI Gas, as part of its merger settlement, agreed to retain three separate LTIIPs by rate district until such time as UGI Gas has uniform rates among the rate districts or such time as the Commission otherwise approves a unified LTIIP. UGI Gas plans to seek approval of a consolidated LTIIP no later than Summer of 2019. As the Company is proposing uniform rates in this proceeding, the Company is also proposing a unified DSIC.

Q. What is the proposed DSIC cap?

A. The Company has included a unified cap of 5% in its proposed tariff, but plans to propose and justify a unified cap of 7.5% concurrently with the consolidated LTIIP filing by the Summer of 2019. The 7.5% cap would be a continuation of the current 7.5% cap applicable to the UGI Gas North and UGI Gas Central Rate Districts.

Q. Is the Company proposing to eliminate any rate schedules in this proceeding?

A. Yes. The Company is proposing to eliminate rate schedules CIAC and CT from the UGI Gas Central Rate District, consistent with the previous removal of these rates from the UGI Gas South and UGI Gas North Rate Districts.

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

A. No, but the Company is proposing to expand the availability of its TED Rider to include the UGI Gas Central Rate District, and to expand the availability of its EE&C program and associated EE&C Rider to include the UGI Gas Central Rate District. The Company has also proposed to expand its POR program to cover the UGI Gas Central and North Rate Districts in separate tariff filings at Docket Nos. A-2018-3000382 and A-2018-3000383, respectively. UGI Gas is also proposing a continuation of the existing five-year GET Gas pilot program.

Q. Is the Company proposing any changes to the calculation of Retainage for rate schedules DS, LFD, XD, and IS?

A. Yes, the Company is proposing to implement a unified retainage percentage across the three UGI Gas rate districts based on current retainage rates which were effective December 1, 2018. The unified retainage rate is reflected in Section 20.1(j) of UGI Gas Exhibit F – Proposed. Please see Table 1 below for the calculation of the current and consolidated retainage rates.

Table 1 – Retainage Rate Calculation

	Current			Consolidated
	UGI South	UGI North	UGI Central	
Sendout	205,290,626	119,716,493	76,791,527	401,798,646
Sales	205,076,771	117,794,286	74,983,677	397,854,734
Retainage	213,854	1,922,207	1,807,850	3,943,911
Percentage	0.1%	1.6%	2.4%	1.0%

IV. TAX CUT AND JOBS ACT CREDIT

Q. Is the Company including any proposal to address the return of the TCJA benefits related to the period January 1, 2018 through June 30, 2018?

A. Yes, consistent with the Commission's May 17, 2018 Orders at Docket No. M-2018-2641242, the Company is proposing in this rate case to return such benefits to customers. Specifically, the Company proposes to use the current TCJA Rider mechanism to credit the TCJA tax benefits associated with the period from January 1, 2018 through June 30, 2018, and to reconcile any applicable under or over-recoveries associated with the TCJA under the current mechanism. The applicable rates will be updated and reflected in Tariff Section 12, Rider C – TCJA Temporary Surcharge. Specifically, the Company will refund the January through June 2018 amount, plus applicable interest, over the 12-month period beginning with the effective date of rates established in this proceeding. The detailed calculation of the TCJA refund amount is discussed in the direct testimony Nicole M. McKinney (UGI Gas St. No. 11). As shown in UGI Gas Exhibit F – Proposed, Rider C – TCJA Temporary Surcharge, the Company is proposing to continue the application of a uniform negative surcharge applicable to all rate classes for the return of the January through June 2018 amount, and has proposed appropriate interest application and reconciliation mechanisms. The proposed surcharge rate is -4.50%.

V. REVENUE ALLOCATION AND RATE DESIGN

Q. Please summarize the Company's revenue allocation and rate design philosophy in this case.

A. The Company's ratemaking goal is to implement reasonable rates that recover its cost of doing business and provide a fair opportunity to earn a reasonable rate of return on its investment to provide utility service. Rates are generally designed to reflect movement toward class cost of service and/or to be competitive with prices of alternate energy sources, including bypass. The Company's revenue allocation and rate design seek to promote and achieve efficient utilization of the Company's facilities and natural gas supplies.

Q. What factors has the Company considered in establishing its rates and rate structures in this proceeding?

A. The Company considered both cost of service and value of service as the primary factors in determining revenue allocation and rate design, along with its proposal to consolidate rates.

Q. Did the Company consider high-use customer migration between rate classes in developing the unified rate proposals made in this case?

A. Given the complex dynamics related to the transition to unified rates on high-use customers, the Company has not included any initial specific projection for migration of high-use customers, or those utilizing greater than 3,000 Mcf per year, between applicable rate classes (Rates N/NT, DS and LFD). However, the Company, the parties and the Commission may need to consider the impact of customer migration to ensure that new rates established in this proceeding accurately reflect the number of customers served under each rate schedule and produce the revenue requirement approved by the Commission.

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

A. UGI Gas proposes to allocate the $71.1 million revenue increase in order to recover the proposed increase and move all non-negotiated rate classes (Rates R/RT, N/NT, DS and LFD) an equal amount (on a percentage basis) toward the overall cost of service. This results in an approximate 41% movement toward the system average rate of return for these rate classes, as shown in Table 2, below. Equal movement of these rate classes, in my view, is a fair and consistent revenue allocation methodology for this proceeding.

Table 2 – Comparison of Relative Rates of Return

Rate	Increase (without gas costs)	Relative ROR-present rates	Relative ROR-proposed rates	Change in relative ROR	Percentage movement toward system average
R/RT	$54.8 MM	0.46	0.68	0.22	41%
N/NT	$13.6 MM	1.34	1.20	-0.14	-41%
DS	$1.3 MM	2.44	1.85	-0.59	-41%
LFD	$0.6 MM	2.90	2.12	-0.77	-41%
XD	$1.0 MM	2.97	2.22	-0.74	-38%
INT	$(0.1) MM	2.35	1.66	-0.69	-51%
Total	$71.1 MM	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 (UGI Gas St. No. 6), under present rates, the residential Rate R customer group (Rates R and RT) is producing a return of 2.87%, as compared to a system average return of 6.2%. This translates to a relative rate of return of 0.46 compared to the system average; a return well below system average. The Company proposes to allocate $54.8 million of the $71.1 million revenue increase to the Rate R customer group, which will move this group 41% closer toward system average. This increase will result in an overall return of 5.64% for the Rate R customer group, compared to the proposed system average of 8.31%, and a relative rate of return of 0.68.

As to rate design, the Company is proposing a Rate R customer charge of $19.00 per month, as compared to the current charge of $13.25 per month in the UGI Gas North Rate District, $14.60 per month in the UGI Gas Central Rate District and $11.75 per month in the UGI Gas South Rate District, to better reflect the customer costs per bill of $31.06 as identified in the cost of service study presented in UGI Gas Exhibit D.

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 8.24% with a relative rate of return of 1.33, which is a return above system average. UGI Gas proposes to allocate $13.6 million of the $71.1 million revenue increase to the Rate N customer group in order to move the Rate N customer group 41% closer toward system average. This increase will result in an overall return of 9.97% or a relative rate of return of 1.2.

As to rate design, the Company is proposing a Rate N customer group customer charge of $37.00 per month, as compared to the current charge of $34.00 per month in the North Rate District, $30.40 per month in the Central Rate District and $16.00 per month in the South Rate District, to better reflect the customer costs per bill of $52.90 as identified within the cost of service study presented in UGI Gas Exhibit D.

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

A. For Rate DS, the applicable transportation rate for small to medium sized customers, current rates are producing a return of 15.02%, with a relative rate of return of 2.42, which is a return above system average. The Company proposes to allocate approximately $1.3 million of the $71.1 million revenue increase to the Rate DS customers in order to move the Rate DS class 41% closer toward system average. This increase will result in an overall class return of 15.36% or a relative rate of return of 1.85.

As to rate design, the Company is proposing a Rate DS monthly customer charge of $280.00 per month, as compared to the current charge of $229.00 per month in the UGI Gas North Rate District, $192.27 per month in the UGI Gas Central Rate District and $290.00 per month in the UGI Gas South Rate District. The proposed customer charge is also supported by the customer costs per bill for Rate DS of $285.98 as identified within the cost of service study presented in UGI Gas Exhibit D.

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

A. For Rate LFD, the applicable transportation rate for medium to large sized customers, current rates are producing a return of 17.85%, with a relative rate of return of 2.88, which is a return above system average. The Company proposes to allocate approximately $0.60 million of the proposed $71.1 million revenue increase to the Rate LFD customers in order to move this customer class 41% toward system average. This increase will result in an overall return of 17.63% or a relative rate of return of 2.12.

As to rate design, the Company is proposing a Rate LFD monthly customer charge of $670.00 per month, as compared to the current charge of $700.00 per month in the UGI Gas North Rate District, $480.62 per month in the UGI Gas Central Rate District and $700.00 per month in the UGI Gas South Rate District. The proposed customer charge is also supported by the customer costs per bill for Rate LFD of $683.45 as identified in the cost of service study presented in UGI Gas Exhibit D.

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

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

Q. Please describe the revenue allocation and rate design for 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 negotiates Rate IS pricing on an individual customer basis. The Company is not proposing any change in present contract distribution rates.

Q. What are the relevant impacts of the unification of base rates and PGC rates by rate class in the three rate districts?

A. Table 3 below provides a comparison of the rate changes by rate class by rate district based on uniform rates for both distribution and PGC rates. The table shows the total percentage change for each rate class in each rate district. In order to reflect a total average bill impact basis for all rate classes, a proxy for gas costs was included in the transportation rates, Rate DS and Rate LFD, using current and proposed PGC rates. As shown in Table 3, under the Company's proposed revenue allocation for those districts receiving rate increases (*i.e.* UGI Gas South and North), no rate class would receive an increase more than two times the average rate district increase. For the UGI Gas Central Rate District, which is receiving an average rate decrease, no rate class receives an increase more than two times the overall system average increase. On the facts of this case, the Company believes this is a reasonable result, particularly given all of the benefits of rate unification discussed in Mr. Szykman's testimony (UGI Gas St. No. 1).

Table 3 – Impact by Rate Class by Rate District

Total Rate Class Impact by Rate District (average bill change)	R/RT	N/NT	DS*	LFD*	Rate District Total Impact	"2x" Reasonableness Standard Applied
South Rate District	19.5%	1.6%	-7.2%	-2.3%	10.9%	21.8%
North Rate District	8.7%	19.4%	15.6%	5.2%	12.1%	24.2%
Central Rate District	-8.5%	9.6%	3.3%	-2.8%	-2.9%	17.8%
Total System					8.9%	17.8%

*Note: Rates DS and LFD include a proxy for gas costs based on unified PGC to provide for a total average bill comparison

Q What are the total proposed revenue changes by rate class by rate district?

A. The total proposed revenue change by rate class by rate district is presented in UGI Gas Exhibit E – Proof of Revenue.

Q. Why does the Company believe rate unification is reasonable and appropriate?

A. The Company believes the impact of moving to uniform rates is reasonable given the many benefits provided by uniform rates as described in the testimony of Paul J. Szykman (UGI Gas St. No. 1). As shown in Table 3, the impact on a rate class by rate district level is reasonable compared to the overall system-wide average percentage change of 8.9%, on a total revenue basis, given the impact of unifying both base distribution rates and PGC rates. Specifically, on a total rate district basis, the Company utilized a standard of two-times ("2x") the system average to gauge if additional rate mitigation steps may be required in order to address the application of the gradualism principal of ratemaking. As shown below in Table 4, no rate district is impacted by greater than 1.36 times the system average. Thus, the Company believes its proposal to move to complete uniform rates is reasonable. In addition, delaying the implementation of uniform distribution and PGC rates and continuing to maintain separate rates by rate district would delay the benefits associated with greater communication clarity to all customers, administrative efficiency and positive impacts of a unified Price-to-Compare for those customers seeking an alternative supplier.

Table 4 – Impact by Rate District

Total Rate District Impact of Uniform Rate Proposal (total revenue change)	Total	Change Relative to System Average
South Rate District	10.9%	1.22
North Rate District	12.1%	1.36
Central Rate District	-2.9%	0.33
Total System-Wide	8.9%	

Q. Is the Company proposing any changes to the EEC Rider.

A. Yes, as explained in the testimony of UGI Gas witness Shaun M. Hart (UGI Gas St. No. 9), the Company proposes to expand the availability of its EE&C program and associated EE&C Rider to include the UGI Gas Central Rate District. The Company is also proposing to unify customer class rates across the three rate districts. The unified rates based on the weighted average of current UGI Gas South and North Rate District's respective EE&C Rider rates, plus the addition of the EE&C Rider costs applicable to the expanded UGI Gas Central Rate District, will be $0.1264/Mcf for Rates R/RT, $0.0551/Mcf for Rates N/NT, $0.0004/Mcf for Rate DS and $0.0007 for Rate LFD. Please see UGI Gas Exhibit DEL-7 for the development of the proposed unified EE&C Rider rates.

Q. Is the Company proposing any changes to the USP Rider?

A. The Company is proposing to unify the USP Rider Rate across the three rate districts. The unified rate, based on the weighted average of the three rate districts, will be $0.1743/Mcf, based on currently effective rates as of December 1, 2018. In addition, the Company is proposing to unify the customer participation adjustment for the calculation of Customer Assistance Program ("CAP") Credits and pre-program arrearage forgiveness in the USP Rider charge. The unified adjustment is 9.2%, and is based on a three-year average for UGI South and North over the period of 2015 – 2017. The relevant data for UGI Central is not reported in similar fashion as UGI South and North and, as such, is unavailable. This updated and unified percentage compares to the current adjustments of

9.4%, 14.1% and 10.86% for UGI South, North and Central rate districts, respectively. Please see UGI Gas Exhibit DEL-8 for the derivation of the unified rate.

Q. Please describe Rate NNS (No Notice Service) and any proposed changes to this rate.

A. Rate NNS is currently an optional daily balancing service offered by the Company to Non-Choice Transportation customers. It provides an alternate, expanded, election of a daily balancing tolerance for transportation customers, allowing a customer to 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 Daily Firm Requirement ("DFR") or Maximum Daily Quantity ("MDQ") contract demand level. As described in the testimony of Angelina M. Borelli (UGI Gas St. No. 12), UGI Gas is proposing to merge the standard basic daily balancing tolerances of 10% (current UGI Gas South Rate District), 2.5% (current UGI Gas North Rate District) and 2.5% (current UGI Gas Central Rate District) into a unified daily balancing service with a firm 4.5% daily balancing tolerance. In addition, customers would have the ability to elect an additional interruptible daily balancing quantity under Rate NNS for up to the DFR or MDQ of the Transportation Customer or Transportation Customer pool.

Q. How were the proposed NNS rates developed?

A. The charge for providing service under Rate NNS is a monthly charge, calculated by using the same cost-based methodology utilized in the Company's last several base rate cases for the various rate districts, updated to reflect current costs, conditions and consolidation to derive a unified rate. UGI Gas Exhibit DEL-9 shows the calculation of the combined NNS charge. The proposed combined NNS rate is $0.1840 per Mcfd of an elected daily No Notice Allowance ("NNA") tolerance quantity under Rate NNS. This compares to a current rate of $0.2660 per Mcfd of elected NNA for UGI Gas North Rate District, $1.6400 per Mcfd of elected NNA for UGI Gas Central Rate District and $0.1320 per Mcfd of elected NNA for UGI Gas South Rate District.

Q. Will the Company continue to credit the revenues received from Rate NNS to PGC Rates?

A. Yes, revenues from this rate schedule will continue to be credited to PGC Rates.

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

A. Rate MBS is a monthly balancing service offered by the Company that allows transportation imbalances of up to 10% for the month to be carried forward in the customer's MBS account for delivery of excess deliveries, or receipt of shortfalls, in subsequent months.

Q. How were the proposed Rate 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 on the same rate design methodology utilized by the UGI Gas rate districts for Rate MBS in their respective most recent base rate cases, updated for current costs and conditions. The proposed MBS rate for Rate DS is $0.0141/Mcf compared to the current rates of

$0.0039/Mcf, $0.0090/Mcf and $0.0050/Mcf for the UGI Gas North, Central and South Rate Districts, respectively. The proposed MBS rate for Rate LFD is $0.0082/Mcf compared to the current rates of $0.0024/Mcf, $0.0057/Mcf and $0.0034/Mcf for the UGI Gas North, Central and South Rate Districts, respectively. The proposed rate for Rate XD is $0.0084/Mcf, as compared to the current rates of $0.0013/Mcf, $0.0017Mcf and $0.0031/Mcf for the UGI Gas North, Central and South Rate Districts, respectively.

Q. Will the Company continue to credit the revenues received from Rate MBS to PGC Rates?

A. Yes, revenues from Rate MBS will continue to be credited to the PGC.

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

A. The Company is proposing to unify the GPC rate based on the weighted average of the current GPCs. The proposed rate is $0.0660/Mcf, as compared to the current GPC rates of $0.0420/Mcf, $0.0400/Mcf and $0.0900Mcf for the UGI Gas North, Central and South Rate Districts, respectively. 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 and unifying the percentages for the MFCs to reflect the actual consolidated uncollectible expense for the last three years. Based on this updated data, the residential MFC will be 2.08%, and the MFC for the commercial class will be 0.24%. Please see UGI Gas Exhibit DEL-12 for additional details. In addition to updating the MFC, these percentage updates will also be incorporated into the POR programs in the UGI Gas North, South and Central Rate Districts in the form of revised unified POR discounts, which are specified in Section 4.12 of the Proposed Gas Choice Supplier Tariff No.7-S.

VI. GET GAS PILOT PROGRAM

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

A. The GET Gas pilot program 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. The Get Gas Pilot Program is the result of a comprehensive settlement approved in a Commission Order entered on February 20, 2014, at Docket No. P-2013-2356232. The current five-year Get Gas pilot program is set to expire in November of 2019, and as UGI Gas witness Shaun M. Hart (UGI Gas St. No. 9) describes in more detail, the Company is proposing to extend the pilot for another five-year period.

Q. Did UGI Gas's 2014 GET Gas 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 is shown in UGI Gas Exhibit SMH-5, and is discussed by Mr. Hart in his testimony.

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

A. While the updated information suggests a decrease in the individual surcharges for the UGI Gas South and North Rate Districts, and a slight increase in the surcharge for the UGI Gas Central Rate District, the Company is proposing a uniform GET Gas Surcharge based on the weighted average of the three rate districts, consistent with its proposal to establish uniform rates. Please see UGI Gas Exhibit SMH-5 and UGI St. No. 9, which provide the calculation of the underlying surcharges by rate district and the resulting unified amounts for residential and commercial GET Gas surcharges. In addition, the Company is proposing to utilize funding amounts from the proposed EEF to further reduce GET Gas surcharge amounts in order to increase market share in current and future GET Gas projects. The creation of the EEF is described in detail in the direct testimony of Paul J. Szykman (UGI Gas St. No. 1). The net GET Gas residential Surcharge amount is $21.75, and was derived based on recent data that supports the assumption that lowering the surcharge leads to greater customer savings which, in turn, leads to increased adoption rates. The net GET Gas commercial fixed monthly surcharge is $7.86 per month and the commercial volumetric charge is $1.07 per Mcf.

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 portion of the GET Gas surcharge and an "adder" portion related to recovery of GET-specific uncollectible and CAP expenses. This amount was calculated by annualizing these portions of the GET Gas surcharge payments for September 30, 2020, plus the 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 $358,000 and is reflected on UGI Gas Exhibit DEL-13.

VII. <u>OTHER TARIFF MODIFICATIONS</u>

Q. Apart from the proposed rate schedule changes 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 make the tariff terms and conditions uniform among rate district tariffs, reflect best practices, add clarity, and update the tariff to reflect the Company's current business practices. Some of the more significant changes to the proposed tariff are:

- The consolidation of the List of Territories Served to encompass all three rate districts.
- Unification of STAS rates as reflected in Section 10 – Rider A, UGI Gas Exhibit F – Proposed Tariff.
- Unification of PGC rates as reflected in Section 11 – Rider B, UGI Gas Exhibit F – Proposed Tariff.
- Unification of TCJA as reflected in Section 12 – Rider C, UGI Gas Exhibit F – Proposed Tariff.
- Unification of the MFC as reflected in Section 13 – Rider D, UGI Gas Exhibit F – Proposed Tariff.
- Unification of the GPC as reflected in Section 14 – Rider E, UGI Gas Exhibit F – Proposed Tariff.
- Unification of the Universal Service Charge as reflected in Section 16 – Rider F, UGI Gas Exhibit F – Proposed Tariff.
- Unification and expansion to include the UGI Gas Central Rate District in the Energy Efficiency and Conservation Charge, as reflected in Section 17 – Rider G, UGI Gas Exhibit F – Proposed Tariff.
- The expansion of the pilot TED Rider to include the UGI Gas Central Rate District, as reflected in Section 18 -Rider H, UGI Gas Exhibit F – Proposed Tariff.

- The expansion of Rider GDE to include the UGI Gas Central Rate District, as reflected in Section 18B -Rider J, UGI Gas Exhibit F – Proposed Tariff.
- The unification of the Retainage percentage across the three rate districts as reflected in Section 20.1(j), UGI Gas Exhibit F – Proposed Tariff.
- Establishment of EEF as reflected in Section 24, UGI Gas Exhibit F – Proposed Tariff.
- Establishment of Incentive Sharing of Interruptible Revenues as reflected in Section 25, UGI Gas Exhibit F – Proposed Tariff.
- The elimination of Rates CIAC and CT for the UGI Gas Central Rate District.
- Updates to Rate NNS and MBS.

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

A. Yes, primarily to reflect the proposed uniform Choice and Non-Choice Transportation rules developed out of the collaborative process further described by Angelina M. Borelli (UGI Gas St. No. 12). The proposed changes to the Company's Choice Supplier Tariff have been incorporated into Proposed Tariff No. 7-S, UGI Gas Exhibit F – Proposed Tariff. In addition to the changes contained in the testimony of Ms. Borelli, an additional key proposed modification to the Choice Supplier Tariff is the unification of the surety calculation for Choice suppliers, based on the current calculation for the UGI Gas South Rate District as reflected in Section 8.2 – Financial Security of the proposed Tariff No. 7S. Specifically, the current UGI Gas South Rate District methodology is proposed to be used for the UGI Gas North and Central Rate Districts' calculations as well.

VIII. PURCHASE OF RECEIVABLES PROGRAM

Q. Did UGI Gas's recent merger settlement contain any provisions concerning its POR program?

A. Yes. Currently UGI Gas only has an operating POR program in the UGI Gas South Rate District. Under the POR program, UGI Gas purchases the gas supply service receivables of Choice Suppliers at a discount to reflect expected uncollectible and administrative expense. As a result, the Company then both bills and collects these amounts from Choice Supplier customers. As part of its PUC-approved settlement in its recent merger proceeding, UGI Gas agreed to extend its POR program to the UGI Gas North and Central Rate Districts, and has proposed the extension in separate tariff filings that have been docketed at Docket Nos. A-2018-3000382 and A-2018-3000383. The expanded programs will mirror the current program for the UGI Gas South Rate District. In addition, the Company is proposing to update the applicable POR discounts in conjunction with the update to the MFC calculation, which will be based on the 3-year average of uncollectible expense by rate class. UGI Gas Exhibit DEL-12 provides the proposed MFC/POR discount percentages. The Company anticipates being able to support POR in the UGI Gas North and Central Rate Districts approximately six months after receiving Commission approval.

Q. Does this conclude your testimony?

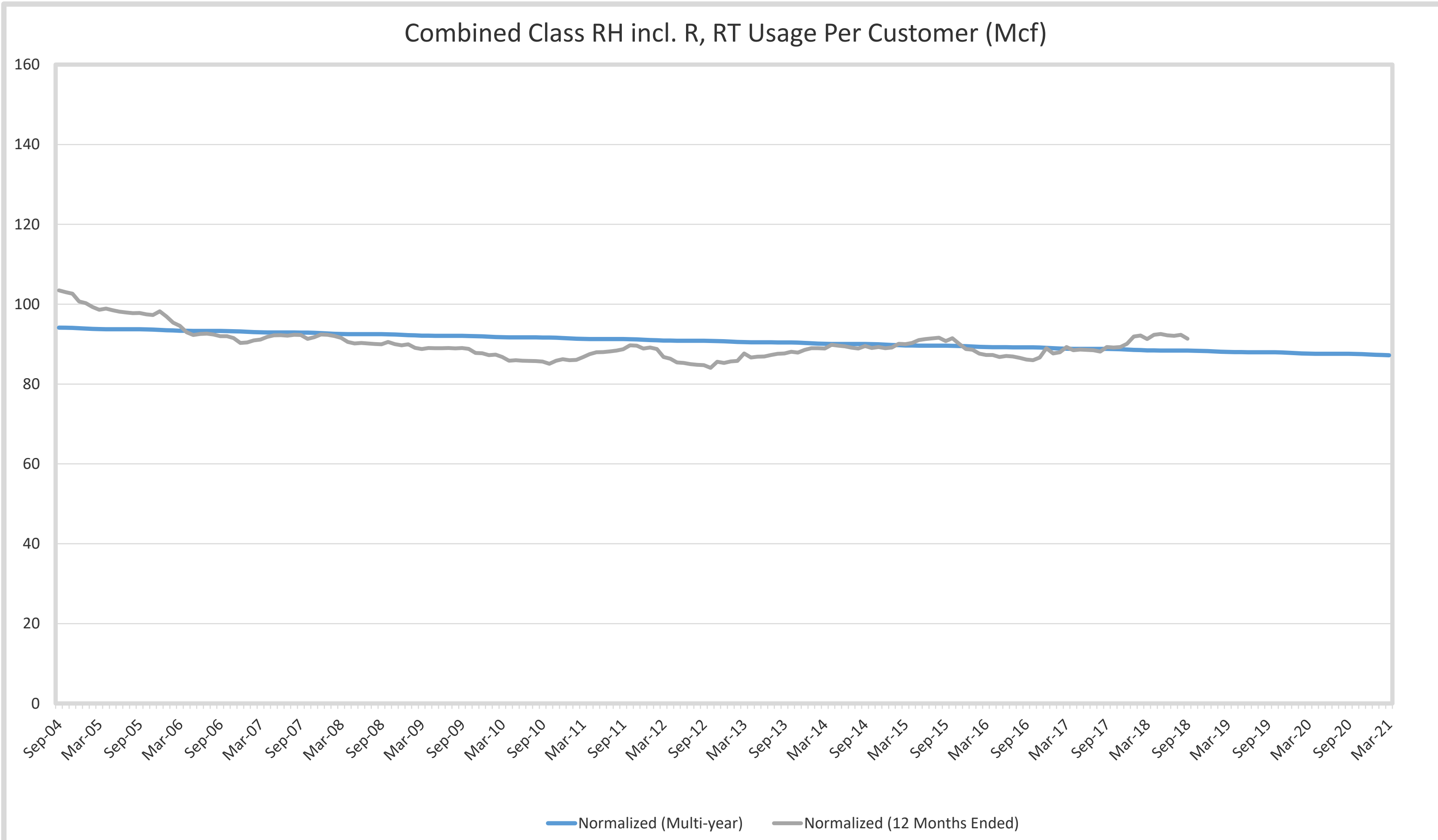
A. Yes.

UGI GAS EXHIBIT DEL-1

UGI Utilities, Inc. - Gas Divison
15 Year Normal Heating Degree Days (2000-2014)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	15 Year Average
Jan	1,171	1,133	920	1,299	1,357	1,217	890	997	1,051	1,292	1,157	1,251	1,002	1,047	1,310	1,142
Feb	920	918	810	1,088	983	939	945	1,178	975	927	1,014	955	814	974	1,114	972
Mar	625	905	735	805	736	942	775	824	819	774	627	836	487	884	976	786
Apr	458	437	419	479	438	377	390	552	371	419	325	414	437	427	467	429
May	152	162	238	241	97	268	184	142	275	179	153	125	73	178	152	176
Jun	42	29	26	74	52	16	44	23	18	41	25	21	39	21	14	33
Jul	10	13	2	0	1	0	1	13	0	15	4	1	1	4	10	5
Aug	21	0	8	2	21	1	5	22	14	16	7	10	7	12	13	11
Sep	170	137	58	72	59	35	123	72	80	118	67	74	110	143	98	95
Oct	372	355	445	455	416	351	428	222	468	440	383	400	335	327	303	381
Nov	733	502	709	574	627	600	552	739	721	571	669	559	785	773	759	660
Dec	1,221	839	1,071	999	1,005	1,121	813	1,006	1,016	1,055	1,162	843	853	1,012	909	997
Totals	5,895	5,429	5,441	6,089	5,792	5,866	5,150	5,791	5,809	5,847	5,594	5,490	4,942	5,802	6,126	5,687

UGI GAS EXHIBITS DEL-2(a) – DEL-2(b)


Combined Class RH incl. R, RT Usage Per Customer (Mcf)
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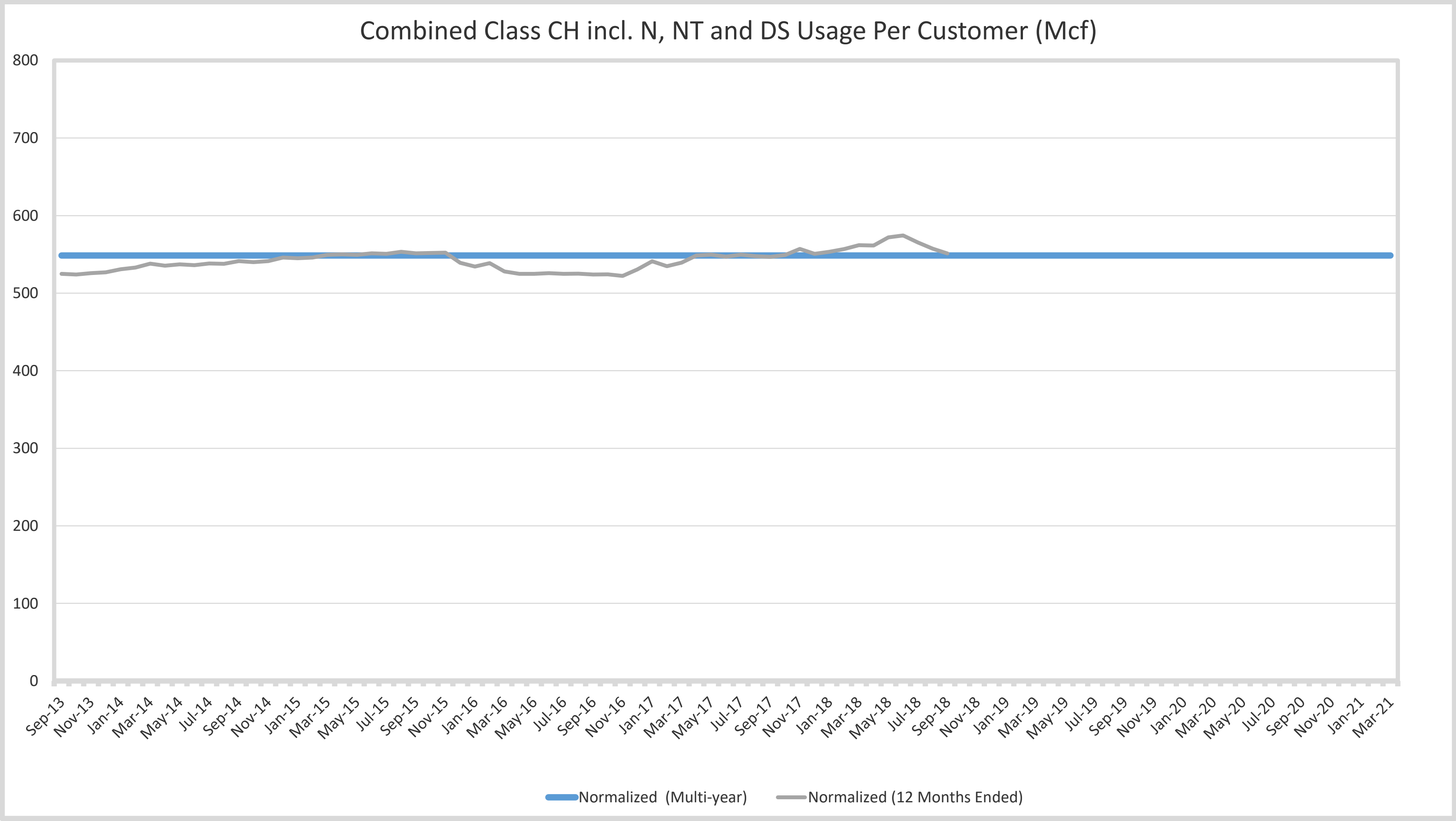
Normalized (Multi-year)
Normalized (12 Months Ended)


Combined Class CH incl. N, NT and DS Usage Per Customer (Mcf)
800
700
600
500
400
300
200
100
0
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16
Jul-16
Sep-16
Nov-16
Jan-17
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May-20
Jul-20
Sep-20
Nov-20
Jan-21
Mar-21
Normalized (Multi-year)
Normalized (12 Months Ended)

UGI GAS EXHIBITS DEL-3(a) – DEL-3(p)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year 2020 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Budget 2020	334,816	873,480	535,728	
Adjustment for Customer Changes	(271)	(2,033)	(1,525)	UGI Utilities, Inc.- Gas Division-Exhibit DEL-3(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	(2,286)	(22,703)	(8,599)	UGI Utilities, Inc.- Gas Division-Exhibit DEL-3(c)/(c)(1)
Adjustment for PGC		(39,037)	0	UGI Utilites, Inc.- Gas Division-Exhibit DEL-3(d)
Adjustment for MFC		(644)	(644)	UGI Utilites, Inc.- Gas Division-Exhibit DEL-3(e)
Adjustment for USP		(2,325)	0	UGI Utilites, Inc.- Gas Division-Exhibit DEL-3(f)
Adjustment for GPC		(220)	(220)	UGI Utilites, Inc.- Gas Division-Exhibit DEL-3(g)
Adjustment for Interruptible		(9,376)	(9,376)	UGI Utilites, Inc.- Gas Division-Exhibit DEL-3(h)
Adjustment for Excess Take		(1,700)	(1,700)	UGI Utilites, Inc.- Gas Division-Exhibit DEL-3(i)
Adjustment for STAS		15	15	UGI Utilites, Inc.- Gas Division-Exhibit DEL-3(j)
Adjustment for EEC Rider		823		UGI Utilites, Inc.- Gas Division-Exhibit DEL-3(k)
Adjustment for EEC Conservation Impact	(201)	(1,487)	(683)	UGI Utilites, Inc.- Gas Division-Exhibit DEL-3(l)
Adjustment for Get Gas		32	32	UGI Utilites, Inc.- Gas Division-Exhibit DEL-3(m)
Adjustment for DSIC Revenues		(6,679)	(6,679)	UGI Utilites, Inc.- Gas Division-Exhibit DEL-3(n)
Adjustment for TCJA		6,494	6,494	UGI Utilites, Inc.- Gas Division-Exhibit DEL-3(o)
Adjustment for GDE		189	0	UGI Utilites, Inc.- Gas Division-Exhibit DEL-3(p)
Fully Projected Future Test Year 2020	332,059	794,830	512,844	

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2020
($ 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	[7] NT	[8] DS	[9] Transport-Other	[10] Grand Total
1	Total Test Year 2020 Revenues (Unadjusted)	$ 7,436	$ 494,215	$ 32,696	$ 7,098	$ 148,847	$ 8,781	$ 45,004	$ 34,167	$ 95,235	$ 873,480
2	PGC Revenues	$ (2,347)	$ (242,108)	$ (2,063)	$ (3,786)	$ (82,305)	$ (5,141)	$ (193)	192	(0)	(337,752)
3	Revenues net of PGC - Margin (Unadjusted)	$ 5,089	$ 252,107	$ 30,634	$ 3,312	$ 66,542	$ 3,640	$ 44,811	$ 34,358	$ 95,235	$ 535,728
4	Average Effective Customers in Test Year 2020 (Unadjusted)	24,713	495,486	74,090	3,247	46,518	652	17,698	1,554	911	664,869
5	Average Annual Margin Per Customer (Weighted Value by District)	$ 0.207	$ 0.865	$ 0.413	$ 1.025	$ 1.579	$ 3.961	$ 2.532	$ 22.109	$ 104.572	$ 0.806
6	Future Test Year 2020 Customers (Fully Adjusted)	23,992	494,385	74,090	3,224	46,589	633	17,698	1,554	904	663,069
7	Change in Customers during Future Test Year 2020 (L 3 - L 1)	(721)	(1,101)	-	(23)	72	(20)	-	-	(7)	(1,800)
8	Annualization of Margin (L 2 * L 5)	$ (149)	$ (952)	$ -	$ (24)	$ 114	$ (77)	$ -	$ -	$ (436)	$ (1,525)
9	Average Annual Revenue Per Customer (Weighted Value by District)	$ 0.301	$ 1.322	$ 0.441	$ 2.188	$ 4.436	$ 9.847	$ 2.543	$ 21.986	$ 104.572	$ 1.314
10	Annualization of Total Revenue (L 4 * L 6)	$ (217)	$ (1,456)	$ -	$ (51)	$ 319	$ (193)	$ -	$ -	$ (436)	$ (2,033)
11	Annualization of PGC Revenues (L 7 - L 5)	$ (68)	$ (504)	$ -	$ (27)	$ 205	$ (115)	$ -	$ -	$ -	$ (508)
12	Total UPC (Unadjusted)-MCF (Weighted Value by District)	16.60	124.35	83.40	231.04	257.74	1,054.64	672.60	7,000.00		
13	Annualization Adjustment for Sales-MMCF (L12 * L7)/1000	(12)	(137)	-	(5)	19	(21)	-	-	(115)	(271)

Notes:

Column [9] further detailed on UGI Gas Exhibit DEL-3(b)(1)

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2020
($ in Thousands)

Adjustment for Customer Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	Total Test Year 2020 Revenues (Unadjusted)	$ 37,665	$ 32,967	$ 1,501	$ 23,103	$ 95,235
2	PGC Revenues	-	-	-	-	-
3	Revenues net of PGC - Margin (Unadjusted)	$ 37,665	$ 32,967	$ 1,501	$ 23,103	$ 95,235
4	Average Effective Customers in Test Year 2020 (Unadjusted)	473	54	51	333	911
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 79.678	$ 610.499	$ 29.434	$ 69.377	$ 104.572
6	Future Test Year 2020 Customers (Fully Adjusted)	470	55	52	327	904
7	Change in Customers during Future Test Year 2020 (L 6 - L 4)	(3)	1	1	(6)	(7)
8	Annualization of Margin	$ (376)	$ 162	$ -	$ (222)	$ (436)
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 79.678	$ 610.499	$ 29.434	$ 69.377	$ 104.572
10	Annualization of Total Revenue	$ (376)	$ 162	$ -	$ (222)	$ (436)
11	Annualization of PGC Revenues (L 10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total Future Test Year 2020 UPC (Unadjusted)-MCF					
13	Annualization Adjustment for Sales-MMCF	(257)	201	-	(59)	(115)

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2020
($ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1] Residential-Non Htg	[2] Residential-Htg	[3] RT	[4] Commercial-Non Htg	[5] Commercial-Htg	[6] Industrial	[7] NT	[8] DS	[9] Large Transp-Other	[10] Reconciliation Adj.	[11] Total
1	Total FY 20 (Unadjusted) UPC-MCF	16.60	92.00	83.40	226.10	348.20	1,525.90	672.60	7,000.00			
2	Future Test Year FY 20 UPC (Fully Adjusted)-MCF	15.90	87.20	83.10	217.70	340.90	1,067.90	709.10	7,000.00			
3	Change in UPC -MCF (L 2 - L1)	(0.70)	(4.80)	(0.30)	(8.40)	(7.30)	(458.00)	36.50	0.00			
4	Future Test Year 2020 Customers (Fully Adjusted)	23,992	494,385	74,090	3,224	46,589	633	17,698	1,554	904	-	663,069
5	Annualization Adjustment for Sales-MMCF (L3*L4)/1000 (District Weighted)	(16)	(2,327)	(23)	(26)	(334)	(299)	647	-	93	-	(2,286)
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18+L20)	$ (136)	$ (19,640)	$ (82)	$ (206)	$ (2,687)	$ (2,314)	$ 2,226	$ -	$ 169	$ (34)	$ (22,703)
7	Total Unit Revenue Adjustment (L6/L5)	$ 8.3510	$ 8.4403	$ 3.5290	$ 7.8472	$ 8.0369	$ 7.7461	$ 3.4411	$ -	$ 1.8218		
8	Distribution Margin Adjustment (L5 *L9)	$ (56)	$ (8,522)	$ (76)	$ (88)	$ (1,160)	$ (1,009)	$ 2,221	$ -	$ 168		$ (8,523)
9	Distribution Unit Rate (Weighted Value by District)	$ 3.4250	$ 3.6625	$ 3.2668	$ 3.3653	$ 3.4710	$ 3.3778	$ 3.4327	$ -	$ 1.8083		
10	PGC Revenue (L5*L11)	$ (74)	$ (10,305)	$ -	$ (117)	$ (1,518)	$ (1,296)	$ -	$ -	$ -	$ (112)	$ (13,422)
11	PGC Unit Rate (Weighted Value by District)	$ 4.5631	$ 4.4287		$ 4.4572	$ 4.5415	$ 4.3365					
12	EE&C Revenue Adjustment (L5*L13)	$ (2)	$ (277)	$ (4)	$ (1)	$ (15)	$ (8)	$ 30	$ -	$ -		$ (276)
13	EE&C Unit Rate (Weighted Value by District)	$ 0.1415	$ 0.1189	$ 0.1524	$ 0.0415	$ 0.0436	$ 0.0265	$ 0.0465	$ -	$ -		
14	USP Revenue Adjustment (L5*L15)	$ (2)	$ (401)	$ (3)	$ -	$ -	$ -	$ -	$ -	$ -		$ (406)
15	USP Unit Rate (Weighted Value by District)	$ 0.1477	$ 0.1721	$ 0.1373	$ -	$ -	$ -	$ -	$ -	$ -		
16	MFC Revenue/Margin Adjustment (L10*L17)	$ (2)	$ (215)	$ -	$ (0)	$ (5)	$ (3)	$ -	$ -	$ -		$ (225)
17	MFC Unit Rate (Weighted Value by District)	$ 0.0215	$ 0.0209	$ -	$ 0.0030	$ 0.0032	$ 0.0025	$ -	$ -	$ -		
18	DSIC Revenue/Margin Adjustment (L8+L12+L14+L16)*L19	$ (2)	$ (298)	$ (3)	$ (3)	$ (44)	$ (53)	$ 78	$ -	$ 11		$ (315)
19	DSIC Unit Rate (Weighted Value by District)	$ 0.0370	$ 0.0317	$ 0.0346	$ 0.0381	$ 0.0376	$ 0.0515	$ 0.0346	$ -	$ 0.0658		
20	TCJA Revenue/Margin Adjustment (L8+L16)*L21	$ 3	$ 378	$ 4	$ 4	$ 56	$ 54	$ (103)	$ -	$ (10)		$ 386
21	TCJA Unit Rate (Weighted Value by District)	$ (0.0469)	$ (0.0433)	$ (0.0461)	$ (0.0475)	$ (0.0477)	$ (0.0536)	$ (0.0462)	$ -	$ (0.0570)		
22	Total Margin Adjustment (L8+L16+L18+L20)	$ (57)	$ (8,657)	$ (75)	$ (88)	$ (1,154)	$ (1,011)	$ 2,196	$ -	$ 169	$ 78	$ (8,599)
23	Total Unit Margin Adjustment (L22/L5)	$ 3.4987	$ 3.7205	$ 3.2393	$ 3.3485	$ 3.4517	$ 3.3830	$ 3.3946	$ -	$ -		

Notes:

Column (9) further detailed on UGI Gas Exhibit DEL-3 (c)(1)
Column (10) Adjustment reflective of interdependent relationship of sequential adjustment impacts.

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2020
($ 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] IS	[5] TOTAL
1	Total FY 20 (Unadjusted) UPC-MCF					
2	Future Test Year FY 20 UPC (Fully Adjusted)-MCF					
3	Change in UPC -MCF	0.00	0.00	0.00	0.00	0.00
4	Future Test Year 2020 Customers (Fully Adjusted)	470	55	52	327	904
5	Annualization Adjustment for Sales-MMCF	93	-	-	-	93
6	Total Revenue Adjustment	$ 169	$ -	$ -	$ -	$ 169
7	Unit Revenue Adjustment (L6/*L5)	1.8218	0.0000	0.0000	0.0000	1.8218
8	Distribution Margin Adjustment (L5 *L9)	$ 168	$ -	$ -	$ -	$ 168
9	Distribution Unit Margin (L8/*L5)	1.8092	0.0000	0.0000	0.0000	1.8092
10	PGC Revenue (L 6 - L22)	$ -	$ -	$ -	$ -	$ -
11	PGC Unit Rate	$ -	$ -	$ -	$ -	$ -
12	EE&C Revenue Adjustment (L5*L12)	$ -	$ -	$ -	$ -	$ -
13	EE&C Unit Rate (Weighted Value by District)	$ -	$ -	$ -	$ -	
14	USP Revenue Adjustment (L5*L15)	$ -	$ -	$ -	$ -	$ -
15	USP Unit Rate (Weighted Value by District)	$ -	$ -	$ -	$ -	
16	MFC Revenue/Margin Adjustment (L10*L17)	$ -	$ -	$ -	$ -	$ -
17	MFC Unit Rate (Weighted Value by District)	$ -	$ -	$ -	$ -	
18	DSIC Revenue/Margin Adjustment (L8+L12+L14+L16)*L19	$ 11	$ -	$ -	$ -	$ 11
19	DSIC Unit Rate (Weighted Value by District)	$ 0.0658	$ -	$ -	$ -	
20	TCJA Revenue/Margin Adjustment (L8+L16)*L21	$ (10)	$ -	$ -	$ -	$ (10)
21	TCJA Unit Rate (Weighted Value by District)	$ (0.0589)	$ -	$ -	$ -	
22	Total Margin Adjustment (L8+L16+L18+L20)	$ 169	$ -	$ -	$ -	$ 169
23	Total Unit Margin Adjustment (L22/L5)	$ 1.8218	$ -	$ -	$ -	$ 1.8218

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2020
($ in Thousands)

Adjustment for PGC

	OCT 2019	NOV 2019	DEC 2019	JAN 2020	FEB 2020	MAR 2020	APR 2020	MAY 2020	JUN 2020	JUL 2020	AUG 2020	SEP 2020	TOTAL
Original Budget PGC Rate FY 20- (Weighted Value by District)	$4.9631	$5.0023	$5.0239	$5.0253	$5.0178	$4.9858	$4.9667	$4.9560	$5.0194	$5.0914	$5.0758	$4.9679	
Fully Projected Future Test Year 2020 PGC Rate-(Weighted Value by District)	$4.3761	$4.3933	$4.4041	$4.4059	$4.4017	$4.3881	$4.3777	$4.3731	$4.4039	$4.4347	$4.4276	$4.3802	
PGC Rate Variance	($0.5870)	($0.6090)	($0.6198)	($0.6194)	($0.6162)	($0.5976)	($0.5889)	($0.5828)	($0.6155)	($0.6568)	($0.6482)	($0.5877)	
Total PGC Volumes	3,873	6,656	10,702	12,705	10,438	8,120	4,372	2,231	1,201	1,015	1,057	1,629	63,998
PGC Revenue Adjustment	($2,274)	($4,054)	($6,634)	($7,869)	($6,431)	($4,853)	($2,575)	($1,300)	($739)	($666)	($685)	($957)	($39,037)

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2020
($ in Thousands)

Adjustment for MFC

	OCT 2019	NOV 2019	DEC 2019	JAN 2020	FEB 2020	MAR 2020	APR 2020	MAY 2020	JUN 2020	JUL 2020	AUG 2020	SEP 2020	TOTAL
PGC Rate Variance - Rate R (Weighted Value by District)	($0.5679)	($0.5897)	($0.6017)	($0.6018)	($0.5980)	($0.5786)	($0.5698)	($0.5676)	($0.6121)	($0.6621)	($0.6512)	($0.5759)	
PGC Rate Variance - Rate N (Weighted Value by District)	($0.6362)	($0.6594)	($0.6670)	($0.6649)	($0.6633)	($0.6472)	($0.6384)	($0.6208)	($0.6231)	($0.6452)	($0.6415)	($0.6160)	
Total PGC Volumes-Rate R	2,788	4,805	7,725	9,166	7,535	5,870	3,152	1,591	835	696	727	1,150	
Total PGC Volumes-Rate N	1,085	1,851	2,978	3,539	2,903	2,251	1,219	640	366	319	330	479	
Total PGC Volumes	3,873	6,656	10,702	12,705	10,438	8,120	4,372	2,231	1,201	1,015	1,057	1,629	63,998
Rate R % (Weighted Value by District)	2.07%	2.07%	2.07%	2.07%	2.07%	2.07%	2.07%	2.07%	2.07%	2.08%	2.07%	2.07%	
Rate N % (Weighted Value by District)	0.28%	0.29%	0.29%	0.29%	0.29%	0.29%	0.28%	0.28%	0.29%	0.29%	0.29%	0.28%	
MFC Rate R Adj Rate	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	
MFC Rate N Adj Rate	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	
Rate R Revenue Variance	($35)	($63)	($104)	($123)	($101)	($76)	($40)	($20)	($11)	($10)	($11)	($15)	
Rate N Revenue Variance	($2)	($3)	($6)	($7)	($6)	($4)	($2)	($1)	($1)	($1)	($1)	($1)	
Total Revenue Variance	($37)	($67)	($110)	($130)	($106)	($80)	($42)	($21)	($12)	($11)	($11)	($16)	($644)

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2020
($ in Thousands)

Adjustment for USP

	OCT 2019	NOV 2019	DEC 2019	JAN 2020	FEB 2020	MAR 2020	APR 2020	MAY 2020	JUN 2020	JUL 2020	AUG 2020	SEP 2020	TOTAL
Original Budget USP Calculation	$680	$1,163	$1,855	$2,195	$1,810	$1,419	$767	$386	$197	$161	$169	$276	$11,078
Correct Budget USP Calculation	$653	$1,117	$1,782	$2,108	$1,738	$1,363	$737	$371	$189	$154	$162	$265	$10,640
Variance to correct Original Budget Calculation	($27)	($46)	($73)	($87)	($72)	($56)	($30)	($15)	($8)	($6)	($7)	($11)	($438)
Original Budget USP Rate FY 20-(Weighted Value by District)	$0.2145	$0.2125	$0.2112	$0.2110	$0.2115	$0.2132	$0.2144	$0.2148	$0.2105	$0.2062	$0.2072	$0.2138	
Future Test Year 2020 USP Rate-(Weighted Value by District)	$0.1785	$0.1752	$0.1731	$0.1727	$0.1736	$0.1762	$0.1784	$0.1791	$0.1718	$0.1648	$0.1665	$0.1773	
USP Rate Variance	($0.0359)	($0.0372)	($0.0381)	($0.0384)	($0.0380)	($0.0369)	($0.0360)	($0.0357)	($0.0387)	($0.0414)	($0.0407)	($0.0365)	
Total Rate R Volumes	3,170	5,472	8,778	10,397	8,554	6,656	3,577	1,795	934	780	815	1,291	52,218
Total Rate R excl CAP Volumes	3,046	5,258	8,435	9,990	8,219	6,395	3,437	1,725	898	749	783	1,241	50,175
USP Rate Revenue Variance	($109)	($196)	($322)	($383)	($312)	($236)	($124)	($62)	($35)	($31)	($32)	($45)	($1,887)
Total Revenue Variance	($136)	($242)	($395)	($470)	($384)	($292)	($154)	($77)	($43)	($37)	($39)	($56)	($2,325)

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2020
($ in Thousands)

Adjustment for GPC

	OCT 2019	NOV 2019	DEC 2019	JAN 2020	FEB 2020	MAR 2020	APR 2020	MAY 2020	JUN 2020	JUL 2020	AUG 2020	SEP 2020	TOTAL
GPC Rate- (Weighted Value by District)	$0.0646	$0.0658	$0.0666	$0.0667	$0.0664	$0.0655	$0.0648	$0.0644	$0.0665	$0.0687	$0.0682	$0.0649	
Volume Variance to Original FY20 Budget	(205)	(349)	(554)	(655)	(540)	(423)	(230)	(118)	(62)	(52)	(55)	(85)	(3,328)
Revenue Variance	($13)	($23)	($37)	($44)	($36)	($28)	($15)	($8)	($4)	($4)	($4)	($6)	($220)

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2020
($ in Thousands)

Adjustment for Interruptibles

Total Unadjusted Interruptble Revenues	$	24,604
Adjustment to Interruptible Revenues @ 40%	$	(9,842)
Adjustment to TCJA for Interruptibles	$	465
Total Interruptible Revenue Adjustment	$	(9,376)

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2020
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MCF)		(283)
$/MCF	$	6.00
Excess Take Revenue/Margin	$	(1,700)

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2020
($ in Thousands)

Adjustment for STAS

	@ -0.07% Unadjusted 2020 TOTAL	@ -0.08% Adjusted 2020 TOTAL	Revenue Adjustment Total
Residential-Non Htg	(5)	(4)	1
Residential-Heating	(377)	(333)	45
Residential-RT	(21)	(17)	4
Total R/RT	(403)	(354)	50
Commercial-Non Htg	(7)	(6)	1
Commercial- Htg	(125)	(108)	18
Commercial-NT	(29)	(25)	4
Industrial	(14)	(10)	5
Industrial-NT	(2)	(2)	0
Total N/NT	(178)	(151)	27
Total DS	(29)	(28)	2
Total LFD	0	(37)	(37)
Total XD-F	0	(19)	(19)
Total Interruptible	0	(8)	(8)
Grand Total	(611)	(596)	15

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2020
($ in Thousands)

Adjustment for EEC Rider

	OCT 2019	NOV 2019	DEC 2019	JAN 2020	FEB 2020	MAR 2020	APR 2020	MAY 2020	JUN 2020	JUL 2020	AUG 2020	SEP 2020	TOTAL
Original Budget R/RT Rate- (Weighted Value by District)	0.1302	0.1316	0.1321	0.1320	0.1319	0.1306	0.1303	0.1300	0.1321	0.1352	0.1346	0.1301	
Future Test Year R/RT Rate- (Weighted Value by District)	0.1323	0.1340	0.1346	0.1344	0.1343	0.1327	0.1324	0.1320	0.1346	0.1384	0.1376	0.1321	
R/RT Rate Variance	0.0021	0.0024	0.0025	0.0024	0.0024	0.0021	0.0021	0.0020	0.0025	0.0031	0.0030	0.0020	
R/RT Rate Volumes	2,680	4,708	7,673	9,146	7,465	5,740	3,028	1,514	827	712	737	1,107	45,338
R/RT Revenue Adjustment	$ 6	$ 11	$ 19	$ 22	$ 18	$ 12	$ 6	$ 3	$ 2	$ 2	$ 2	$ 2	$ 106
Original Budget N/NT Rate- (Weighted Value by District)	0.0193	0.0193	0.0195	0.0197	0.0196	0.0196	0.0194	0.0194	0.0195	0.0193	0.0193	0.0195	
Future Test Year N/NT Rate- (Weighted Value by District)	0.0522	0.0522	0.0522	0.0523	0.0522	0.0523	0.0522	0.0522	0.0522	0.0522	0.0522	0.0522	
N/NT Rate Variance	0.0329	0.0329	0.0327	0.0326	0.0327	0.0326	0.0328	0.0328	0.0327	0.0329	0.0329	0.0327	
N/NT Rate Volumes	1,570	2,610	4,077	4,790	3,969	3,105	1,742	951	588	533	546	734	25,214
N/NT Revenue Adjustment	$ 52	$ 86	$ 133	$ 156	$ 130	$ 101	$ 57	$ 31	$ 19	$ 18	$ 18	$ 24	$ 825
Original Budget DS Rate-(Weighted Value by District)	(0.0122)	(0.0160)	(0.0203)	(0.0252)	(0.0239)	(0.0263)	(0.0225)	(0.0206)	(0.0207)	(0.0174)	(0.0117)	(0.0153)	
Future Test Year DS Rate-(Weighted Value by District)	(0.0266)	(0.0258)	(0.0248)	(0.0237)	(0.0240)	(0.0234)	(0.0243)	(0.0247)	(0.0247)	(0.0254)	(0.0267)	(0.0259)	
DS Rate Variance	(0.0144)	(0.0098)	(0.0045)	0.0015	(0.0001)	0.0028	(0.0018)	(0.0041)	(0.0040)	(0.0080)	(0.0150)	(0.0107)	
DS Rate Volumes	457	763	1,208	1,575	1,459	1,212	687	412	304	269	274	305	8,926
DS Revenue Adjustment	$ (7)	$ (7)	$ (5)	$ 2	$ (0)	$ 3	$ (1)	$ (2)	$ (1)	$ (2)	$ (4)	$ (3)	$ (27)
Original Budget LFD Rate-(Weighted Value by District)	-	-	-	-	-	-	-	-	-	-	-	-	
Future Test Year LFD Rate-(Weighted Value by District)	(0.0048)	(0.0048)	(0.0048)	(0.0047)	(0.0046)	(0.0048)	(0.0046)	(0.0047)	(0.0048)	(0.0048)	(0.0047)	(0.0047)	
LFD Rate Variance	(0.0048)	(0.0048)	(0.0048)	(0.0047)	(0.0046)	(0.0048)	(0.0046)	(0.0047)	(0.0048)	(0.0048)	(0.0047)	(0.0047)	
LFD Rate Volumes	1,334	1,569	1,795	1,997	1,776	1,622	1,389	1,229	1,115	1,084	1,119	1,169	17,197
LFD Revenue Adjustment	$ (6)	$ (7)	$ (9)	$ (9)	$ (8)	$ (8)	$ (6)	$ (6)	$ (5)	$ (5)	$ (5)	$ (6)	$ (81)
Total Revenue Adjustment	$ 44	$ 82	$ 139	$ 172	$ 140	$ 109	$ 56	$ 27	$ 15	$ 12	$ 11	$ 17	$ 823

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2020
($ in Thousands)

Adjustment for EE&C Conservation Impact

EE&C Plan (Version 12/21/2018)

Yearly Gas Savings by Rate Class 2020 - 2035 (Cumulative MMBtus)

Rate Class Description	*Fiscal Year* 2020	2021	2022	2023	2024	MMBTU 5 Year Average	BTU	MCF 5 Year Average	Customers FY20 Retail Htg & Choice Htg	EE&C UPC Conservation Adj
Residential (R/RT)	145,463	157,325	171,179	175,233	176,395	165,119	1.036	159,315	564,259	**(0.3)**
Nonresidential (N/NT)	29,620	38,139	45,037	50,308	50,308	42,682	1.035	41,245	63,512	**(0.6)**
Total	**175,083**	**195,464**	**216,217**	**225,540**	**226,703**	**207,802**		**200,560**	**627,771**	

Line #	Description	[1] Residential-Htg	[2] Res Htg-RT	[3] Commercial-Htg	[4] Com Htg-NT	[5] Industrial	[6] Industrial -NT	[7] Total
1	Future Test Year FY 20 UPC (Fully Adjusted)-MCF	87.2	87.0	340.9	689.7	1,067.9	1,993.4	
2	Future Test Year FY 20 UPC (Fully Adjusted-Incl EE&C Impact)-MCF	86.9	86.7	340.3	689.1	1,067.3	1,992.8	
3	Change in UPC -MCF	(0.3)	(0.3)	(0.6)	(0.6)	(0.6)	(0.6)	
4	End of Year Customers-Total FY 20	494,385	69,874	46,589	15,825	633	465	627,771
5	Annualization Adjustment for Sales-MMCF (L3*L4)/1000	(140)	(20)	(30)	(10)	(0)	(0)	(201)
6	Total Revenue Adjustment (L10+L12+L14+L23)	$ (1,144)	$ (75)	$ (236)	$ (30)	$ (3)	$ (1)	$ (1,487)
7	Total Unit Revenue Adjustment (L6/L5)	8.1941	3.7798	7.7843	2.8719	7.8467	2.4276	7.4160
8	Distribution Margin Adjustment (L5 *L9)	$ (474)	$ (69)	$ (101)	$ (29)	$ (1)	$ (1)	$ (675)
9	Distribution Unit Rate (Weighted Value by District)	3.3932	3.4869	3.3301	2.8581	3.4232	2.4192	
10	PGC Revenue (L5*L11)	$ (621)	$ -	$ (134)	$ -	$ (2)	$ -	$ (757)
11	PGC Unit Rate (Weighted Value by District)	4.4515		4.4233		4.3900		
12	EE&C Revenue Adjustment (L5*L12)	$ (19)	$ (4)	$ (1)	$ (0)	$ (0)	$ (0)	$ (24)
13	EE&C Unit Rate (Weighted Value by District)	$ 0.1345	$ 0.1838	$ 0.0298	$ 0.0304	$ 0.0242	$ 0.0278	
14	USP Revenue Adjustment (L5*L15)	$ (21)	$ (3)	$ -	$ -	$ -	$ -	$ (24)
15	USP Unit Rate (Weighted Value by District)	$ 0.1509	$ 0.1404	$ -	$ -	$ -	$ -	
16	MFC Revenue/Margin Adjustment (L10*L17)	$ (13)	$ -	$ (0)	$ -	$ (0)	$ -	$ (14)
17	MFC Unit Rate (Weighted Value by District)	$ 0.0213	$ -	$ 0.0024	$ -	$ 0.0024	$ -	
18	DSIC Revenue/Margin Adjustment (L8+L12+L14+L16)*L19	$ (18)	$ (3)	$ (5)	$ (1)	$ (0)	$ (0)	$ (26)
19	DSIC Unit Rate (Weighted Value by District)	$ 0.0333	$ 0.0343	$ 0.0479	$ 0.0430	$ 0.0538	$ 0.0408	
20	TCJA Revenue/Margin Adjustment (L8+L16)*L21	$ 22	$ 3	$ 5	$ 1	$ 0	$ 0	$ 32
21	TCJA Unit Rate (Weighted Value by District)	$ (0.0448)	$ (0.0464)	$ (0.0512)	$ (0.0493)	$ (0.0545)	$ (0.0493)	
22	Total Margin Adjustment (L8+L16+L18+L20)	$ (483)	$ (68)	$ (101)	$ (29)	$ (1)	$ (1)	$ (683)
23	Total Unit Margin Adjustment (L22/L5)	$ 3.4572	$ 3.4556	$ 3.3312	$ 2.8415	$ 3.4325	$ 2.3998	

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2020
($ in Thousands)

Adjustment for Get Gas Surcharge

Budget 2020	$	326
Fully Projected Future Test Year 2020	$	358
Get Gas Revenue Adjustment	$	32

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2020
($ in Thousands)

Adjustment for DSIC

	@ 4.45% Unadjusted 2020 TOTAL	@ 3.31% Adjusted 2020 TOTAL	Revenue Adjustment Total
RES. G	247	177	(70)
H	12,087	8,734	(3,352)
SUBTOTAL R	12,333	8,911	(3,423)
RT	1,568	1,116	(452)
TOTAL	13,901	10,027	(3,874)
COM. G	167	127	(40)
H	3,197	2,361	(836)
SUBTOTAL C-N	3,364	2,488	(876)
NT	1,993	1,424	(569)
DS	1,295	952	(344)
IS	531	379	(151)
XD-F	88	57	(31)
XD-I	47	48	0
LFD	657	487	(171)
TOTAL	7,975	5,834	(2,141)
IND.	216	186	(30)
SUBTOTAL I-N	216	186	(30)
NT	170	125	(45)
DS	360	271	(89)
IS	497	360	(138)
XD-F	548	460	(87)
XD-I	30	25	(5)
LFD	1,231	961	(270)
TOTAL	3,052	2,389	(664)
GRAND TOTAL	24,929	18,250	(6,679)

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2020
($ in Thousands)

Adjustment for TCJA

	@ -5.70% Unadjusted 2020 TOTAL	@ -4.48% Adjusted 2020 TOTAL	Revenue Adjustment Total
RES. G	(291)	(232)	59
H	(14,193)	(11,115)	3,078
SUBTOTAL R	(14,484)	(11,347)	3,137
RT	(1,763)	(1,415)	348
TOTAL	(16,247)	(12,762)	3,485
COM. G	(199)	(158)	41
H	(3,867)	(3,057)	810
SUBTOTAL C-N	(4,066)	(3,215)	851
NT	(2,389)	(1,911)	477
DS	(1,573)	(1,251)	323
IS	(646)	(517)	128
XD-F	(115)	(92)	23
XD-I	(52)	(40)	12
LFD	(803)	(634)	169
TOTAL	(9,644)	(7,661)	1,983
IND.	(247)	(196)	52
SUBTOTAL I-N	(247)	(196)	52
NT	(199)	(161)	38
DS	(437)	(345)	91
IS	(718)	(578)	139
XD-F	(1,742)	(1,351)	391
XD-I	(56)	(43)	13
LFD	(1,467)	(1,165)	302
TOTAL	(4,866)	(3,839)	1,026
GRAND TOTAL	(30,757)	(24,262)	6,494

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2020
($ in Thousands)

Adjustment for GDE Rider

	OCT 2019	NOV 2019	DEC 2019	JAN 2020	FEB 2020	MAR 2020	APR 2020	MAY 2020	JUN 2020	JUL 2020	AUG 2020	SEP 2020	TOTAL
Original Budget DS Rate	-	-	-	-	-	-	-	-	-	-	-	-	
Future Test Year DS Rate-(Weighted Value by District)	0.0111	0.0108	0.0108	0.0110	0.0103	0.0104	0.0105	0.0109	0.0110	0.0110	0.0104	0.0112	
DS Rate Variance	0.0111	0.0108	0.0108	0.0110	0.0103	0.0104	0.0105	0.0109	0.0110	0.0110	0.0104	0.0112	
DS Rate Volumes	342	515	732	842	777	607	385	250	184	177	199	214	5,223
DS Revenue Adjustment	$ 4	$ 6	$ 8	$ 9	$ 8	$ 6	$ 4	$ 3	$ 2	$ 2	$ 2	$ 2	$ 56
Original Budget LFD Rate	-	-	-	-	-	-	-	-	-	-	-	-	
Future Test Year LFD Rate-(Weighted Value by District)	0.0136	0.0137	0.0136	0.0137	0.0140	0.0139	0.0137	0.0139	0.0137	0.0136	0.0138	0.0137	
LFD Rate Variance	0.0136	0.0137	0.0136	0.0137	0.0140	0.0139	0.0137	0.0139	0.0137	0.0136	0.0138	0.0137	
LFD Rate Volumes	753	885	1,006	1,115	989	933	768	698	636	612	627	656	9,678
LFD Revenue Adjustment	$ 10	$ 12	$ 14	$ 15	$ 14	$ 13	$ 11	$ 10	$ 9	$ 8	$ 9	$ 9	$ 133
Total Revenue Adjustment	$ 14	$ 18	$ 22	$ 25	$ 22	$ 19	$ 15	$ 12	$ 11	$ 10	$ 11	$ 11	$ 189

UGI GAS EXHIBITS DEL-4(a) – DEL-4(o)

UGI Utilities Inc.- Gas Division
Future Test Year 2019 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Budget 2019	332,726	851,979	520,788	
Adjustment for Customer Changes	(386)	(1,949)	(1,547)	UGI Utilities, Inc.- Gas Division-Exhibit DEL-4(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	(1,931)	(21,963)	(8,336)	UGI Utilities, Inc.- Gas Division-Exhibit DEL-4(c)/(c)(1)
Adjustment for PGC		(37,997)	0	UGI Utilites, Inc.- Gas Division-Exhibit DEL-4(d)
Adjustment for MFC		(627)	(627)	UGI Utilites, Inc.- Gas Division-Exhibit DEL-4(e)
Adjustment for USP		(2,280)	0	UGI Utilites, Inc.- Gas Division-Exhibit DEL-4(f)
Adjustment for GPC		(202)	(202)	UGI Utilites, Inc.- Gas Division-Exhibit DEL-4(g)
Adjustment for Interruptible		(9,121)	(9,121)	UGI Utilites, Inc.- Gas Division-Exhibit DEL-4(h)
Adjustment for Excess Take		(1,700)	(1,700)	UGI Utilites, Inc.- Gas Division-Exhibit DEL-4(i)
Adjustment for STAS		67	67	UGI Utilites, Inc.- Gas Division-Exhibit DEL-4(j)
Adjustment for EEC Rider		553		UGI Utilites, Inc.- Gas Division-Exhibit DEL-4(k)
Adjustment for Get Gas		67	67	UGI Utilites, Inc.- Gas Division-Exhibit DEL-4(l)
Adjustment for DSIC Revenues		1,315	1,315	UGI Utilites, Inc.- Gas Division-Exhibit DEL-4(m)
Adjustment for TCJA		6,412	6,412	UGI Utilites, Inc.- Gas Division-Exhibit DEL-4(n)
Adjustment for GDE		184	0	UGI Utilites, Inc.- Gas Division-Exhibit DEL-4(o)
Future Test Year 2019	330,409	784,740	507,116	

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2019
($ 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	[7] NT	[8] DS	[9] Transport-Other	[10] Grand Total
1	Total Test Year 2019 Revenues (Unadjusted)	$ 7,827	$ 480,343	$ 32,200	$ 7,138	$ 144,453	$ 8,715	$ 44,321	$ 33,297	$ 93,684	$ 851,979
2	PGC Revenues	$ (2,496)	$ (237,050)	$ (2,063)	$ (3,833)	$ (80,363)	$ (5,129)	$ (193)	187	(252)	(331,191)
3	Revenues net of PGC - Margin (Unadjusted)	$ 5,331	$ 243,294	$ 30,137	$ 3,305	$ 64,090	$ 3,586	$ 44,128	$ 33,484	$ 93,433	$ 520,788
4	Average Effective Customers in Test Year 2019 (Unadjusted)	26,273	485,255	74,090	3,287	45,489	663	17,698	1,552	911	655,218
5	Average Annual Margin Per Customer (Weighted Value by District)	$ 0.204	$ 0.848	$ 0.407	$ 1.008	$ 1.568	$ (0.386)	$ 2.493	$ 25.941	$ 102.561	$ 0.795
6	Future Test Year 2019 Customers (Fully Adjusted)	25,499	484,176	74,090	3,263	45,560	650	17,698	1,554	897	653,387
7	Change in Customers during Future Test Year 2019 (L 3 - L 1)	(774)	(1,080)	-	(24)	71	(13)	-	2	(14)	(1,831)
8	Annualization of Margin (L 2 * L 5)	$ (157)	$ (915)	$ -	$ (24)	$ 112	$ 5	$ -	$ 45	$ (612)	$ (1,547)
9	Average Annual Revenue Per Customer (Weighted Value by District)	$ 0.298	$ 1.306	$ 0.435	$ 2.171	$ 4.416	$ 0.268	$ 2.504	$ 25.531	$ 102.837	$ 1.300
10	Annualization of Total Revenue (L 4 * L 6)	$ (230)	$ (1,410)	$ -	$ (52)	$ 315	$ (3)	$ -	$ 44	$ (612)	$ (1,949)
11	Annualization of PGC Revenues (L 7 - L 5)	$ (73)	$ (495)	$ -	$ (28)	$ 203	$ (8)	$ -	$ (1)	$ -	$ (401)
12	Total UPC (Unadjusted)-MCF (Weighted Value by District)	16.60	123.96	83.40	230.70	258.90	(425.49)	672.60	6,949.20		
13	Annualization Adjustment for Sales-MMCF (L12 * L7)/1000	(13)	(134)	-	(6)	18	5	-	12	(270)	(386)

Notes:

Column [9] further detailed on UGI Gas Exhibit DEL-4(b)(1)

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for Customer Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	Total Test Year 2019 Revenues (Unadjusted)	$ 37,143	$ 32,606	$ 1,475	$ 22,461	$ 93,684
2	PGC Revenues	(252)	-	-	-	(252)
3	Revenues net of PGC - Margin (Unadjusted)	$ 36,891	$ 32,606	$ 1,475	$ 22,461	$ 93,433
4	Average Effective Customers in Test Year 2019 (Unadjusted)	473	54	51	332	911
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 77.938	$ 603.969	$ 28.652	$ 67.613	$ 102.561
6	Future Test Year 2019 Customers (Fully Adjusted)	467	54	50	326	897
7	Change in Customers during Future Test Year 2019 (L 6 - L 4)	(6)	0	(1)	(6)	(14)
8	Annualization of Margin	$ (416)	$ 38	$ (4)	$ (230)	$ (612)
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 78.469	$ 603.969	$ 28.652	$ 67.613	$ 102.837
10	Annualization of Total Revenue	$ (416)	$ 38	$ (4)	$ (230)	$ (612)
11	Annualization of PGC Revenues (L 10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total Future Test Year 2019 UPC (Unadjusted)-MCF					
13	Annualization Adjustment for Sales-MMCF	(272)	148	(85)	(61)	(270)

UGI Gas Exhibit DEL-4(c)

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1] Residential-Non Htg	[2] Residential-Htg	[3] RT	[4] Commercial-Non Htg	[5] Commercial-Htg	[6] Industrial	[7] NT	[8] DS	[9] Large Transp-Other	[10] Total
1	Total FY 19 (Unadjusted) UPC-MCF	16.60	92.20	83.40	225.80	348.40	1,565.80	672.60	6,949.20		
2	Future Test Year FY 19 UPC (Fully Adjusted)-MCF	16.00	87.70	83.10	222.50	337.50	1,138.00	709.10	6,949.20		
3	Change in UPC -MCF (L 2 - L1)	(0.60)	(4.50)	(0.30)	(3.30)	(10.90)	(427.80)	36.50	0.00		
4	Future Test Year 2019 Customers (Fully Adjusted)	25,499	484,176	74,090	3,263	45,560	650	17,698	1,554	897	653,387
5	Annualization Adjustment for Sales-MMCF (L3*L4)/1000 (District Weighted)	(17)	(2,114)	(23)	(11)	(491)	(303)	647	-	382	(1,931)
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18+L20)	$ (145)	$ (17,837)	$ (82)	$ (83)	$ (3,891)	$ (2,334)	$ 2,225	$ -	$ 184	$ (21,963)
7	Total Unit Revenue Adjustment (L6/L5)	$ 8.3567	$ 8.4373	$ 3.5290	$ 7.8800	$ 7.9199	$ 7.6947	$ 3.4404	$ -	$ 0.4820	
8	Distribution Margin Adjustment (L5 *L9)	$ (59)	$ (7,738)	$ (76)	$ (36)	$ (1,671)	$ (1,019)	$ 2,220	$ -	$ 187	$ (8,192)
9	Distribution Unit Rate (Weighted Value by District)	$ 3.4324	$ 3.6605	$ 3.2668	$ 3.3985	$ 3.4000	$ 3.3596	$ 3.4321	$ -	$ 0.4911	
10	PGC Revenue (L5*L11)	$ (79)	$ (9,361)	$ -	$ (47)	$ (2,209)	$ (1,305)	$ -	$ -	$ -	$ (13,001)
11	PGC Unit Rate (Weighted Value by District)	$ 4.5612	$ 4.4281		$ 4.4554	$ 4.4959	$ 4.3023				
12	EE&C Revenue Adjustment (L5*L13)	$ (2)	$ (251)	$ (4)	$ (0)	$ (21)	$ (7)	$ 30	$ -	$ -	$ (256)
13	EE&C Unit Rate (Weighted Value by District)	$ 0.1410	$ 0.1189	$ 0.1524	$ 0.0389	$ 0.0435	$ 0.0238	$ 0.0466	$ -	$ -	
14	USP Revenue Adjustment (L5*L15)	$ (3)	$ (364)	$ (3)	$ -	$ -	$ -	$ -	$ -	$ -	$ (370)
15	USP Unit Rate (Weighted Value by District)	$ 0.1481	$ 0.1722	$ 0.1373	$ -	$ -	$ -	$ -	$ -	$ -	
16	MFC Revenue/Margin Adjustment (L10*L17)	$ (2)	$ (195)	$ -	$ (0)	$ (7)	$ (3)	$ -	$ -	$ -	$ (207)
17	MFC Unit Rate (Weighted Value by District)	$ 0.0215	$ 0.0209	$ -	$ 0.0030	$ 0.0031	$ 0.0024	$ -	$ -	$ -	
18	DSIC Revenue/Margin Adjustment (L8+L12+L14+L16)*L19	$ (2)	$ (269)	$ (3)	$ (1)	$ (63)	$ (55)	$ 78	$ -	$ 3	$ (313)
19	DSIC Unit Rate (Weighted Value by District)	$ 0.0371	$ 0.0315	$ 0.0346	$ 0.0408	$ 0.0368	$ 0.0537	$ 0.0346	$ -	$ 0.0161	
20	TCJA Revenue/Margin Adjustment (L8+L16)*L21	$ 3	$ 343	$ 4	$ 2	$ 79	$ 56	$ (102)	$ -	$ (6)	$ 377
21	TCJA Unit Rate (Weighted Value by District)	$ (0.0470)	$ (0.0432)	$ (0.0461)	$ (0.0489)	$ (0.0471)	$ (0.0546)	$ (0.0462)	$ -	$ (0.0346)	
22	Total Margin Adjustment (L8+L16+L18+L20)	$ (61)	$ (7,860)	$ (75)	$ (36)	$ (1,661)	$ (1,022)	$ 2,195	$ -	$ 184	$ (8,336)
23	Total Unit Margin Adjustment (L22/L5)	$ 3.5064	$ 3.7180	$ 3.2393	$ 3.3857	$ 3.3805	$ 3.3686	$ 3.3938	$ -	$ -	

Notes:

Column (9) further detailed on UGI Gas Exhibit DEL-4 (c)(1)

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2019
($ 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] IS	[5] TOTAL
1	Total FY 19 (Unadjusted) UPC-MCF					
2	Future Test Year FY 19 UPC (Fully Adjusted)-MCF					
3	Change in UPC -MCF	0.00	0.00	0.00	0.00	0.00
4	Future Test Year 2019 Customers (Fully Adjusted)	467	54	50	326	897
5	Annualization Adjustment for Sales-MMCF	-	370	-	12	382
6	Total Revenue Adjustment	$ 27	$ 108	$ -	$ 50	$ 184
7	Unit Revenue Adjustment (L6/*L5)	0.0000	0.2914	0.0000	4.2026	0.4820
8	Distribution Margin Adjustment (L5 *L9)	$ 27	$ 110	$ -	$ 50	$ 187
9	Distribution Unit Margin (L8/*L5)	0.0000	0.2978	0.0000	4.2563	0.4911
10	PGC Revenue (L 6 - L22)	$ -	$ -	$ -	$ -	$ -
11	PGC Unit Rate	$ -	$ -	$ -	$ -	$ -
12	EE&C Revenue Adjustment (L5*L12)	$ -	$ -	$ -	$ -	$ -
13	EE&C Unit Rate (Weighted Value by District)	$ -	$ -	$ -	$ -	
14	USP Revenue Adjustment (L5*L15)	$ -	$ -	$ -	$ -	$ -
15	USP Unit Rate (Weighted Value by District)	$ -	$ -	$ -	$ -	
16	MFC Revenue/Margin Adjustment (L10*L17)	$ -	$ -	$ -	$ -	$ -
17	MFC Unit Rate (Weighted Value by District)	$ -	$ -	$ -	$ -	
18	DSIC Revenue/Margin Adjustment (L8+L12+L14+L16)*L19	$ 0	$ 1	$ -	$ 2	$ 3
19	DSIC Unit Rate (Weighted Value by District)	$ 0.01799	$ 0.00720	$ -	$ -	$ 0.01607
20	TCJA Revenue/Margin Adjustment (L8+L16)*L21	$ (1)	$ (3)	$ -	$ (2)	$ (6)
21	TCJA Unit Rate (Weighted Value by District)	$ (0.03536)	$ (0.02870)	$ -	$ -	$ (0.03459)
22	Total Margin Adjustment (L8+L16+L18+L20)	$ 27	$ 108	$ -	$ 50	$ 184
23	Total Unit Margin Adjustment (L22/L5)	$ -	$ 0.2914	$ -	$ 4.2026	$ 0.4820

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for PGC

	OCT 2018	NOV 2018	DEC 2018	JAN 2019	FEB 2019	MAR 2019	APR 2019	MAY 2019	JUN 2019	JUL 2019	AUG 2019	SEP 2019	TOTAL
Original Budget PGC Rate FY 19- (Weighted Value by District)	$4.9549	$4.9944	$5.0159	$5.0173	$5.0101	$4.9781	$4.9591	$4.9484	$5.0119	$5.0839	$5.0682	$4.9602	
Future Test Year 2019 PGC Rate- (Weighted Value by District)	$4.3728	$4.3902	$4.4011	$4.4029	$4.3987	$4.3852	$4.3748	$4.3702	$4.4010	$4.4318	$4.4247	$4.3772	
PGC Rate Variance	($0.5821)	($0.6042)	($0.6149)	($0.6144)	($0.6113)	($0.5929)	($0.5843)	($0.5782)	($0.6108)	($0.6521)	($0.6435)	($0.5830)	
Total PGC Volumes	3,805	6,531	10,495	12,458	10,236	7,967	4,293	2,192	1,180	997	1,038	1,601	62,793
PGC Revenue Adjustment	($2,215)	($3,945)	($6,453)	($7,654)	($6,258)	($4,724)	($2,508)	($1,267)	($721)	($650)	($668)	($933)	($37,997)

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for MFC

	OCT 2018	NOV 2018	DEC 2018	JAN 2019	FEB 2019	MAR 2019	APR 2019	MAY 2019	JUN 2019	JUL 2019	AUG 2019	SEP 2019	TOTAL
PGC Rate Variance - Rate R (Weighted Value by District)	($0.5528)	($0.5737)	($0.5851)	($0.5853)	($0.5817)	($0.5630)	($0.5547)	($0.5530)	($0.5967)	($0.6454)	($0.6348)	($0.5612)	
PGC Rate Variance - Rate N (Weighted Value by District)	($0.6209)	($0.6424)	($0.6492)	($0.6471)	($0.6458)	($0.6305)	($0.6228)	($0.6061)	($0.6080)	($0.6294)	($0.6259)	($0.6017)	
Total PGC Volumes-Rate R	2,788	4,805	7,725	9,166	7,535	5,870	3,152	1,591	835	696	727	1,150	
Total PGC Volumes-Rate N	1,085	1,851	2,978	3,539	2,903	2,251	1,219	640	366	319	330	479	
Total PGC Volumes	3,873	6,656	10,702	12,705	10,438	8,120	4,372	2,231	1,201	1,015	1,057	1,629	63,998
Rate R % (Weighted Value by District)	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.03%	2.04%	2.04%	2.03%	
Rate N % (Weighted Value by District)	0.27%	0.28%	0.28%	0.28%	0.28%	0.28%	0.27%	0.27%	0.28%	0.29%	0.28%	0.27%	
MFC Rate R Adj Rate	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	
MFC Rate N Adj Rate	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	
Rate R Revenue Variance	($35)	($62)	($101)	($120)	($98)	($74)	($39)	($20)	($11)	($10)	($10)	($14)	
Rate N Revenue Variance	($2)	($3)	($5)	($7)	($5)	($4)	($2)	($1)	($1)	($1)	($1)	($1)	
Total Revenue Variance	($36)	($65)	($107)	($127)	($103)	($78)	($41)	($21)	($12)	($11)	($11)	($15)	($627)

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for USP

	OCT 2018	NOV 2018	DEC 2018	JAN 2019	FEB 2019	MAR 2019	APR 2019	MAY 2019	JUN 2019	JUL 2019	AUG 2019	SEP 2019	TOTAL
Original Budget USP Calculation	$670	$1,146	$1,826	$2,161	$1,782	$1,398	$756	$380	$194	$158	$166	$272	$10,911
Correct Budget USP Calculation	$644	$1,100	$1,754	$2,075	$1,712	$1,343	$726	$365	$186	$152	$160	$262	$10,480
Variance to correct Original Budget Calculation	($26)	($45)	($72)	($86)	($71)	($55)	($30)	($15)	($8)	($6)	($7)	($11)	($432)
Original Budget USP Rate FY 19- (Weighted Value by District)	$0.2148	$0.2128	$0.2115	$0.2113	$0.2118	$0.2134	$0.2146	$0.2151	$0.2108	$0.2065	$0.2075	$0.2141	
Future Test Year 2019 USP Rate- (Weighted Value by District)	$0.1790	$0.1757	$0.1735	$0.1731	$0.1740	$0.1767	$0.1788	$0.1795	$0.1723	$0.1653	$0.1669	$0.1778	
USP Rate Variance	($0.0358)	($0.0371)	($0.0380)	($0.0382)	($0.0378)	($0.0368)	($0.0359)	($0.0356)	($0.0385)	($0.0412)	($0.0406)	($0.0363)	
Total Rate R Volumes	3,120	5,383	8,632	10,223	8,411	6,548	3,520	1,768	920	767	802	1,272	51,364
Total Rate R excl CAP Volumes	2,998	5,172	8,294	9,822	8,082	6,291	3,382	1,698	884	737	770	1,222	49,354
USP Rate Revenue Variance	($107)	($192)	($315)	($375)	($306)	($231)	($121)	($60)	($34)	($30)	($31)	($44)	($1,848)
Total Revenue Variance	($134)	($237)	($387)	($461)	($376)	($287)	($151)	($75)	($42)	($37)	($38)	($55)	($2,280)

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for GPC

	OCT 2018	NOV 2018	DEC 2018	JAN 2019	FEB 2019	MAR 2019	APR 2019	MAY 2019	JUN 2019	JUL 2019	AUG 2019	SEP 2019	TOTAL
GPC Rate- (Weighted Value by District)	$0.0644	$0.0656	$0.0663	$0.0665	$0.0662	$0.0652	$0.0645	$0.0642	$0.0663	$0.0685	$0.0680	$0.0647	
Volume Variance to Original FY19 Budget	(188)	(321)	(510)	(602)	(497)	(389)	(212)	(109)	(58)	(49)	(51)	(79)	(3,065)
Revenue Variance	($12)	($21)	($34)	($40)	($33)	($25)	($14)	($7)	($4)	($3)	($3)	($5)	($202)

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for Interruptibles

Total Unadjusted Interruptble Revenues	$	23,936
Adjustment to Interruptible Revenues @ 40%	$	(9,574)
Adjustment to TCJA for Interruptibles	$	453
Total Interruptible Revenue Adjustment	$	(9,121)

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MCF)		(283)
$/MCF	$	6.00
Excess Take Revenue/Margin	$	(1,700)

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for STAS

	Unadjusted 2019 TOTAL	Adjusted 2019 TOTAL	Revenue Adjustment Total
Residential-Non Htg	(6)	(5)	1
Residential-Heating	(371)	(339)	32
Residential-RT	(21)	(16)	4
Total R/RT	(398)	(360)	38
Commercial-Non Htg	(7)	(6)	1
Commercial- Htg	(124)	(112)	12
Commercial-NT	(29)	(23)	5
Industrial	(14)	(13)	0
Industrial-NT	(2)	(2)	1
Total N/NT	(175)	(157)	19
Total DS	(29)	(26)	3
Total LFD	(39)	(36)	3
Total XD-F	(24)	(22)	2
Total Interruptible	(20)	(17)	3
Grand Total	(685)	(618)	67

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for EEC Rider

	OCT 2018	NOV 2018	DEC 2018	JAN 2019	FEB 2019	MAR 2019	APR 2019	MAY 2019	JUN 2019	JUL 2019	AUG 2019	SEP 2019	TOTAL
Original Budget R/RT Rate- (Weighted Value by District)	0.1299	0.1313	0.1319	0.1317	0.1316	0.1303	0.1300	0.1297	0.1319	0.1349	0.1344	0.1298	
Future Test Year R/RT Rate- (Weighted Value by District)	0.1319	0.1336	0.1343	0.1340	0.1339	0.1324	0.1320	0.1317	0.1343	0.1380	0.1373	0.1318	
R/RT Rate Variance	0.0020	0.0023	0.0024	0.0024	0.0024	0.0021	0.0020	0.0019	0.0024	0.0031	0.0030	0.0020	
R/RT Rate Volumes	2,635	4,626	7,537	8,983	7,333	5,641	2,976	1,489	813	700	725	1,089	44,547
R/RT Revenue Adjustment	$ 5	$ 11	$ 18	$ 21	$ 17	$ 12	$ 6	$ 3	$ 2	$ 2	$ 2	$ 2	$ 102
Original Budget N/NT Rate- (Weighted Value by District)	0.0193	0.0193	0.0195	0.0197	0.0196	0.0196	0.0194	0.0194	0.0195	0.0193	0.0193	0.0195	
Future Test Year N/NT Rate- (Weighted Value by District)	0.0522	0.0522	0.0522	0.0523	0.0523	0.0523	0.0522	0.0522	0.0522	0.0522	0.0522	0.0522	
N/NT Rate Variance	0.0328	0.0329	0.0327	0.0326	0.0327	0.0326	0.0328	0.0328	0.0327	0.0329	0.0329	0.0327	
N/NT Rate Volumes	1,553	2,579	4,023	4,725	3,917	3,066	1,722	941	582	528	540	727	24,903
N/NT Revenue Adjustment	$ 51	$ 85	$ 132	$ 154	$ 128	$ 100	$ 56	$ 31	$ 19	$ 17	$ 18	$ 24	$ 815
Original Budget DS Rate-(Weighted Value by District)	(0.0115)	(0.0155)	(0.0199)	(0.0249)	(0.0236)	(0.0260)	(0.0224)	(0.0204)	(0.0205)	(0.0172)	(0.0115)	(0.0151)	
Future Test Year DS Rate-(Weighted Value by District)	(0.0268)	(0.0259)	(0.0249)	(0.0237)	(0.0240)	(0.0235)	(0.0243)	(0.0248)	(0.0247)	(0.0255)	(0.0268)	(0.0260)	
DS Rate Variance	(0.0153)	(0.0104)	(0.0050)	0.0012	(0.0004)	0.0024	(0.0019)	(0.0044)	(0.0042)	(0.0083)	(0.0153)	(0.0109)	
DS Rate Volumes	450	754	1,195	1,564	1,448	1,200	684	410	302	268	273	304	8,853
DS Revenue Adjustment	$ (7)	$ (8)	$ (6)	$ 2	$ (1)	$ 3	$ (1)	$ (2)	$ (1)	$ (2)	$ (4)	$ (3)	$ (31)
Original Budget LFD Rate-(Weighted Value by District)	0.0147	0.0147	0.0147	0.0147	0.0146	0.0147	0.0146	0.0147	0.0147	0.0147	0.0147	0.0147	
Future Test Year LFD Rate-(Weighted Value by District)	(0.0048)	(0.0048)	(0.0048)	(0.0047)	(0.0045)	(0.0047)	(0.0046)	(0.0047)	(0.0048)	(0.0048)	(0.0047)	(0.0047)	
LFD Rate Variance	(0.0195)	(0.0195)	(0.0195)	(0.0193)	(0.0192)	(0.0194)	(0.0192)	(0.0194)	(0.0196)	(0.0196)	(0.0194)	(0.0194)	
LFD Rate Volumes	1,332	1,562	1,786	1,989	1,767	1,613	1,380	1,227	1,112	1,082	1,116	1,167	17,133
LFD Revenue Adjustment	$ (26)	$ (30)	$ (35)	$ (38)	$ (34)	$ (31)	$ (26)	$ (24)	$ (22)	$ (21)	$ (22)	$ (23)	$ (332)
Total Revenue Adjustment	$ 23	$ 57	$ 109	$ 139	$ 111	$ 83	$ 35	$ 8	$ (2)	$ (4)	$ (6)	$ (0)	$ 553

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for Get Gas Surcharge

Budget 2019	$	208
Future Test Year 2019	$	275
Get Gas Revenue Adjustment	$	67

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for DSIC

	Unadjusted 2019 TOTAL	Adjusted 2019 TOTAL	Revenue Adjustment Total
RES. G	178	189	11
H	7,760	8,565	805
SUBTOTAL R	7,938	8,754	816
RT	1,072	1,116	45
TOTAL	9,009	9,870	861
COM. G	122	129	7
H	2,156	2,312	156
SUBTOTAL C-N	2,278	2,441	162
NT	1,357	1,424	66
DS	885	939	54
IS	352	368	16
XD-F	53	57	4
XD-I	45	47	1
LFD	447	479	33
TOTAL	5,418	5,754	336
IND.	176	182	6
SUBTOTAL I-N	176	182	6
NT	122	125	3
DS	253	269	17
IS	350	359	9
XD-F	419	458	39
XD-I	23	25	3
LFD	919	962	43
TOTAL	2,262	2,380	118
GRAND TOTAL	16,689	18,004	1,315

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for TCJA

	Unadjusted 2019 TOTAL	Adjusted 2019 TOTAL	Revenue Adjustment Total
RES. G	(310)	(247)	63
H	(13,923)	(10,900)	3,023
SUBTOTAL R	(14,233)	(11,147)	3,086
RT	(1,763)	(1,415)	348
TOTAL	(15,996)	(12,562)	3,434
COM. G	(201)	(160)	42
H	(3,783)	(2,990)	794
SUBTOTAL C-N	(3,984)	(3,149)	835
NT	(2,389)	(1,911)	477
DS	(1,553)	(1,234)	319
IS	(627)	(502)	125
XD-F	(114)	(91)	23
XD-I	(51)	(39)	11
LFD	(793)	(627)	166
TOTAL	(9,510)	(7,553)	1,957
IND.	(244)	(193)	51
SUBTOTAL I-N	(244)	(193)	51
NT	(199)	(161)	38
DS	(434)	(343)	91
IS	(717)	(578)	139
XD-F	(1,732)	(1,344)	388
XD-I	(56)	(44)	13
LFD	(1,461)	(1,160)	301
TOTAL	(4,843)	(3,822)	1,021
GRAND TOTAL	(30,350)	(23,937)	6,412

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for GDE Rider

	OCT 2018	NOV 2018	DEC 2018	JAN 2019	FEB 2019	MAR 2019	APR 2019	MAY 2019	JUN 2019	JUL 2019	AUG 2019	SEP 2019	TOTAL
Original Budget DS Rate	-	-	-	-	-	-	-	-	-	-	-	-	
Future Test Year DS Rate-(Weighted Value by District)	0.0111	0.0108	0.0108	0.0109	0.0102	0.0103	0.0104	0.0109	0.0109	0.0109	0.0104	0.0111	
DS Rate Variance	0.0111	0.0108	0.0108	0.0109	0.0102	0.0103	0.0104	0.0109	0.0109	0.0109	0.0104	0.0111	
DS Rate Volumes	342	514	731	839	774	604	383	249	183	177	199	213	5,209
DS Revenue Adjustment	$ 4	$ 6	$ 8	$ 9	$ 8	$ 6	$ 4	$ 3	$ 2	$ 2	$ 2	$ 2	$ 56
Original Budget LFD Rate	-	-	-	-	-	-	-	-	-	-	-	-	
Future Test Year LFD Rate-(Weighted Value by District)	0.0134	0.0135	0.0135	0.0136	0.0138	0.0138	0.0136	0.0136	0.0134	0.0133	0.0135	0.0134	
LFD Rate Variance	0.0134	0.0135	0.0135	0.0136	0.0138	0.0138	0.0136	0.0136	0.0134	0.0133	0.0135	0.0134	
LFD Rate Volumes	739	868	989	1,097	968	911	746	683	622	599	613	642	9,478
LFD Revenue Adjustment	$ 10	$ 12	$ 13	$ 15	$ 13	$ 13	$ 10	$ 9	$ 8	$ 8	$ 8	$ 9	$ 129
Total Revenue Adjustment	$ 14	$ 17	$ 21	$ 24	$ 21	$ 19	$ 14	$ 12	$ 10	$ 10	$ 10	$ 11	$ 184

UGI GAS EXHIBITS DEL-5(a) – DEL-5(l)

UGI Utilities Inc.- Gas Division
Historic Year 2018 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Actual 2018	263,878	895,668	536,869	
Adjustment for Customer Changes	(184)	(8,954)	(2,482)	UGI Utilities, Inc.- Gas Division-Exhibit DEL-5(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	4,671	(21,823)	(8,791)	UGI Utilities, Inc.- Gas Division-Exhibit DEL-5(c)/(c)(1)
Adjustment for PGC		(14,806)	0	UGI Utilites, Inc.- Gas Division-Exhibit DEL-5(d)
Adjustment for MFC		(239)	(239)	UGI Utilites, Inc.- Gas Division-Exhibit DEL-5(e)
Adjustment for USP		(958)	0	UGI Utilites, Inc.- Gas Division-Exhibit DEL-5(f)
Adjustment for GPC		(238)	(238)	UGI Utilites, Inc.- Gas Division-Exhibit DEL-5(g)
Adjustment for Interruptible		(9,711)	(9,711)	UGI Utilites, Inc.- Gas Division-Exhibit DEL-5(h)
Adjustment for Excess Take		(1,842)	(1,842)	UGI Utilites, Inc.- Gas Division-Exhibit DEL-5(i)
Adjustment for STAS		40	40	UGI Utilites, Inc.- Gas Division-Exhibit DEL-5(j)
Adjustment for Get Gas		18	18	UGI Utilites, Inc.- Gas Division-Exhibit DEL-5(k)
Adjustment for DSIC Revenues		176	176	UGI Utilites, Inc.- Gas Division-Exhibit DEL-5(l)
Historic Year 2018	268,365	837,331	513,800	

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2018
($ 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	[7] NT	[8] DS	[9] Transport-Other	[10] Grand Total
1	Total Historic Year 2018 Revenues	$ 8,601	$ 489,094	$ 32,396	$ 7,977	$ 151,293	$ 8,690	$ 47,492	$ 47,695	$ 102,429	$ 895,668
2	PGC Revenues	$ (2,720)	$ (241,168)	$ (2,090)	$ (4,315)	$ (84,908)	$ (5,046)	$ (249)	(12,843)	(5,459)	(358,799)
3	Revenues net of PGC - Margin	$ 5,881	$ 247,927	$ 30,306	$ 3,661	$ 66,386	$ 3,644	$ 47,242	$ 34,852	$ 96,970	$ 536,869
4	Average Effective Customers in Historic Year	28,223	477,195	72,281	3,367	44,711	697	17,529	1,521	902	646,426
5	Average Annual Margin Per Customer (Weighted Value by District)	$ 0.221	$ 0.500	$ 0.400	$ 1.092	$ 1.513	$ 5.051	$ 3.127	$ 14.453	$ 107.556	$ 0.831
6	Number of Customer at End of Year	27,272	468,479	77,774	3,333	44,071	676	18,052	1,463	905	642,025
7	Change in Customers during Historic Year (L 3 - L 1)	(951)	(8,716)	5,493	(34)	(640)	(21)	523	(58)	3	(4,401)
8	Annualization of Margin (L 2 * L 5)	$ (210)	$ (4,359)	$ 2,195	$ (38)	$ (968)	$ (105)	$ 1,635	$ (840)	$ 208	$ (2,482)
9	Average Annual Revenue Per Customer (Weighted Value by District)	$ 0.317	$ 1.008	$ 0.428	$ 2.389	$ 3.550	$ 12.102	$ 3.137	$ 25.124	$ 113.611	$ 1.386
10	Annualization of Total Revenue (L 4 * L 6)	$ (301)	$ (8,789)	$ 2,352	$ (82)	$ (2,271)	$ (251)	$ 1,641	$ (1,461)	$ 208	$ (8,954)
11	Annualization of PGC Revenues (L 7 - L 5)	$ (91)	$ (4,429)	$ 157	$ (45)	$ (1,303)	$ (146)	$ 6	$ (620)	$ -	$ (6,472)
12	Total Actual UPC (Weighted Value by District)	16.29	88.89	81.39	228.78	340.68	1,123.23	756.03	7,333.49		
13	Annualization Adjustment for Sales-MMCF (L12 * L7)/1000	(15)	(775)	447	(8)	(218)	(23)	395	(426)	439	(184)

Notes:

Column [9] further detailed on UGI Gas Exhibit DEL-5(b)(1)

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

Adjustment for Customer Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	Total Historic Year 2018 Revenues	$ 40,192	$ 35,870	$ 1,627	$ 24,740	$ 102,429
2	PGC Revenues	(1,994)	(2,895)	(31)	(539)	(5,459)
3	Revenues net of PGC - Margin	$ 38,197	$ 32,976	$ 1,596	$ 24,201	$ 96,970
4	Average Effective Customers in Historic Year	471	52	55	323	902
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 81.053	$ 629.574	$ 28.976	$ 74.963	$ 107.556
6	Number of Customer at End of Year	474	54	56	321	905
7	Change in Customers during Historic Year (L 3 - L 1)	3	2	1	(2)	3
8	Annualization of Margin (L 2 * L 5)	$ 44	$ 231	$ 351	$ (418)	$ 208
9	Average Annual Revenue Per Customer	$ 85.284	$ 684.841	$ 29.533	$ 76.634	$ 113.611
10	Annualization of Total Revenue (L 4 * L 6)	$ 44	$ 231	$ 351	$ (418)	$ 208
11	Annualization of PGC Revenues (L 7 - L 5)	$ -	$ -	$ -	$ -	$ -
12	Total Actual UPC					
13	Annualization Adjustment for Sales-MMCF (L12 * L7)/1000	19	227	419	(227)	439

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

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1] Residential-Non Htg	[2] Residential-Htg	[3] RT	[4] Commercial-Non Htg	[5] Commercial-Htg	[6] Industrial	[7] NT	[8] DS	[9] Large Transp-Other	[10] Total
1	Total FY 18 Actual UPC-MCF	15.90	91.30	83.40	235.10	356.30	1,309.70	707.10	7,175.30		
2	Fully Adjusted FY 18 UPC -MCF	16.00	88.30	83.20	239.70	330.00	1,339.30	708.40	7,204.60		
3	Change in UPC -MCF (L 2 - L1)	0.10	(3.00)	(0.20)	4.60	(26.30)	29.60	1.30	29.30		
4	Number of Customer at End of Year	27,272	468,479	77,774	3,333	44,071	676	18,052	1,463	905	642,025
5	Annualization Adjustment for Sales-MMCF (L3*L4)/1000 (District Weighted)	1	(1,434)	(7)	15	(1,168)	17	1	53	7,194	4,671
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18+L20)	$ 12	$ (13,061)	$ 47	$ 129	$ (9,483)	$ 167	$ (198)	$ (247)	$ 811	$ (21,823)
7	Total Unit Revenue Adjustment (L6/L5)	$ 13.1009	$ 9.1083	$ (6.8485)	$ 8.6712	$ 8.1196	$ 10.0469	$ (395.8543)	$ (4.6522)	$ 0.1128	
8	Distribution Margin Adjustment (L5 *L9)	$ 11	$ (5,504)	$ 51	$ 51	$ (3,721)	$ 65	$ (200)	$ (274)	$ 830	$ (8,691)
9	Distribution Unit Rate (Weighted Value by District)	$ 11.5234	$ 3.8384	$ (7.4568)	$ 3.4214	$ 3.1863	$ 3.9168	$ (399.1247)	$ (5.1489)	$ 0.1153	
10	PGC Revenue (L5*L11)	$ 1	$ (6,996)	$ -	$ 78	$ (5,764)	$ 102	$ -	$ -	$ (1)	$ (12,580)
11	PGC Unit Rate (Weighted Value by District)	$ 1.1021	$ 4.8786		$ 5.2464	$ 4.9354	$ 6.1313				
12	EE&C Revenue Adjustment (L5*L13)	$ (0)	$ (150)	$ (6)	$ 0	$ (22)	$ 0	$ 4	$ 33	$ (1)	$ (143)
13	EE&C Unit Rate (Weighted Value by District)	$ (0.3444)	$ 0.1044	$ 0.9143	$ 0.0125	$ 0.0189	$ 0.0056	$ 7.3375	$ -	$ -	
14	USP Revenue Adjustment (L5*L15)	$ 0	$ (315)	$ 3	$ -	$ -	$ -	$ -	$ -	$ -	$ (312)
15	USP Unit Rate (Weighted Value by District)	$ 0.4594	$ 0.2200	$ (0.4080)	$ -	$ -	$ -	$ -	$ -	$ -	
16	MFC Revenue/Margin Adjustment (L10*L17)	$ 0	$ (145)	$ -	$ 0	$ (17)	$ 0	$ -	$ -	$ -	$ (162)
17	MFC Unit Rate (Weighted Value by District)	$ 0.0304	$ 0.0208	$ -	$ 0.0030	$ 0.0030	$ 0.0035	$ -	$ -	$ -	
18	DSIC Revenue/Margin Adjustment (L8+L12+L14+L16)*L19	$ 1	$ (192)	$ 0	$ 2	$ (124)	$ 3	$ (20)	$ (35)	$ 9	$ (357)
19	DSIC Unit Rate (Weighted Value by District)	$ 0.0998	$ 0.0314	$ 0.0013	$ 0.0422	$ 0.0331	$ 0.0456	$ 0.1024	$ -	$ 0.0107	
20	TCJA Revenue/Margin Adjustment (L8+L16)*L21	$ (1)	$ 242	$ (1)	$ (3)	$ 166	$ (3)	$ 18	$ 29	$ (26)	$ 421
21	TCJA Unit Rate (Weighted Value by District)	$ (0.0725)	$ (0.0428)	$ (0.0149)	$ (0.0496)	$ (0.0444)	$ (0.0529)	$ (0.0904)	$ -	$ (0.0312)	
22	Total Margin Adjustment (L8+L16+L18+L20)	$ 11	$ (5,600)	$ 50	$ 51	$ (3,697)	$ 65	$ (202)	$ (280)	$ 811	$ (8,791)
23	Total Unit Margin Adjustment (L22/L5)	$ 11.8838	$ 3.9053	$ (7.3548)	$ 3.4123	$ 3.1653	$ 3.9100	$ (403.1918)	$ -	$ -	

Notes:

Column (9) further detailed on UGI Gas Exhibit DEL-5 (c)(1)

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2018
($ 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] IS	[5] TOTAL
1	Total FY 18 Actual UPC-MCF					
2	Fully Adjusted FY 18 UPC -MCF					
3	Change in UPC -MCF	0.00	0.00	0.00	0.00	0.00
4	Number of Customer at End of Year	474	54	56	321	905
5	Annualization Adjustment for Sales-MMCF	(115)	7,273	57	(21)	7,194
6	Total Revenue Adjustment (L8+L12+L14+L16+L18+L20)	$ 95	$ 612	$ 57	$ 47	$ 811
7	Unit Revenue Adjustment (L6/*L5)	(0.8244)	0.0842	1.0033	(2.2412)	0.1128
8	Distribution Margin Adjustment (L5 *L9)	$ 98	$ 626	$ 58	$ 47	$ 830
9	Distribution Unit Margin (L8/*L5)	(0.8490)	0.0860	1.0254	(2.2660)	0.1153
10	PGC Revenue (L 6 - L22)	$ (1)	$ -	$ -	$ -	$ (1)
11	PGC Unit Rate	$ -	$ -	$ -	$ -	$ -
12	EE&C Revenue Adjustment (L5*L12)	$ (1)	$ -	$ -	$ -	$ (1)
13	EE&C Unit Rate (Weighted Value by District)	$ 0.00990	$ -	$ -	$ -	
14	USP Revenue Adjustment (L5*L15)	$ -	$ -	$ -	$ -	$ -
15	USP Unit Rate (Weighted Value by District)	$ -	$ -	$ -	$ -	
16	MFC Revenue/Margin Adjustment (L10*L17)	$ -	$ -	$ -	$ -	$ -
17	MFC Unit Rate (Weighted Value by District)	$ -	$ -	$ -	$ -	
18	DSIC Revenue/Margin Adjustment (L8+L12+L14+L16)*L19	$ 2	$ 5	$ 0	$ 2	$ 9
19	DSIC Unit Rate (Weighted Value by District)	$ 0.02153	$ 0.00720	$ -	$ -	$ 0.01073
20	TCJA Revenue/Margin Adjustment (L8+L16)*L21	$ (4)	$ (18)	$ (2)	$ (2)	$ (26)
21	TCJA Unit Rate (Weighted Value by District)	$ (0.03858)	$ (0.02870)	$ -	$ -	$ (0.03112)
22	Total Margin Adjustment (L8+L16+L18+L20)	$ 96	$ 612	$ 57	$ 47	$ 813
23	Total Unit Margin Adjustment (L22/L5)	$ (0.8343)	$ 0.0842	$ 1.0033	$ (2.2412)	$ 0.1130

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

Adjustment for PGC

	OCT 2017	NOV 2017	DEC 2017	JAN 2018	FEB 2018	MAR 2018	APR 2018	MAY 2018	JUN 2018	JUL 2018	AUG 2018	SEP 2018	TOTAL
PGC Rate FY 18- (Weighted Value by District)	$5.4728	$5.4944	$5.2237	$5.2177	$5.2057	$5.2058	$5.1743	$5.1215	$5.0500	$5.0125	$4.9973	$5.1456	
September 2018 PGC Rate- (Weighted Value by District)	$4.9737	$5.0007	$5.0081	$5.0029	$4.9912	$4.9916	$4.9631	$4.9150	$5.0500	$5.0125	$4.9973	$5.1456	
PGC Rate Variance	($0.4991)	($0.4937)	($0.2156)	($0.2148)	($0.2145)	($0.2142)	($0.2112)	($0.2065)	$0.0000	$0.0000	$0.0000	$0.0000	
Total PGC Volumes	2,333	6,534	11,020	12,792	8,305	9,218	5,696	1,610	1,224	931	958	1,133	61,754
PGC Revenue Adjustment	($1,164)	($3,226)	($2,376)	($2,748)	($1,781)	($1,975)	($1,203)	($333)	$0	$0	$0	$0	($14,806)

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

Adjustment for MFC

	OCT 2017	NOV 2017	DEC 2017	JAN 2018	FEB 2018	MAR 2018	APR 2018	MAY 2018	JUN 2018	JUL 2018	AUG 2018	SEP 2018	TOTAL
PGC Rate Variance - Rate R (Weighted Value by District)	($0.4969)	($0.4828)	($0.2102)	($0.2054)	($0.2051)	($0.2084)	($0.2033)	($0.2016)	$0.0000	$0.0000	$0.0000	$0.0000	
PGC Rate Variance - Rate N (Weighted Value by District)	($0.5049)	($0.5205)	($0.2326)	($0.2377)	($0.2374)	($0.2284)	($0.2321)	($0.2141)	$0.0000	$0.0000	$0.0000	$0.0000	
Total PGC Volumes-Rate R	1,699	4,631	8,363	9,070	5,897	6,531	4,129	981	815	615	596	775	
Total PGC Volumes-Rate N	634	1,903	2,657	3,721	2,408	2,686	1,567	629	409	316	362	359	
Total PGC Volumes	2,333	6,534	11,020	12,792	8,305	9,218	5,696	1,610	1,224	931	958	1,133	61,754
Rate R % (Weighted Value by District)	2.08%	2.07%	2.07%	2.07%	2.07%	2.07%	2.07%	2.06%	2.10%	2.09%	2.09%	2.06%	
Rate N % (Weighted Value by District)	0.28%	0.28%	0.29%	0.29%	0.29%	0.29%	0.29%	0.28%	0.28%	0.28%	0.27%	0.31%	
MFC Rate R Adj Rate	($0.01)	($0.01)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	$0.00	$0.00	$0.00	$0.00	
MFC Rate N Adj Rate	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	$0.00	$0.00	$0.00	$0.00	
Rate R Revenue Variance	($18)	($48)	($39)	($41)	($27)	($30)	($19)	($4)	$0	$0	$0	$0	
Rate N Revenue Variance	($1)	($3)	($2)	($3)	($2)	($2)	($1)	($0)	$0	$0	$0	$0	
Total Revenue Variance	($19)	($50)	($41)	($44)	($28)	($32)	($20)	($5)	$0	$0	$0	$0	($239)

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

Adjustment for USP

	OCT 2017	NOV 2017	DEC 2017	JAN 2018	FEB 2018	MAR 2018	APR 2018	MAY 2018	JUN 2018	JUL 2018	AUG 2018	SEP 2018	TOTAL
USP Rate FY 18- (Weighted Value by District)	$0.3275	$0.3278	$0.2160	$0.2169	$0.2177	$0.2167	$0.2186	$0.2191	$0.2090	$0.2117	$0.2106	$0.2025	
September 2018 USP Rate- (Weighted Value by District)	$0.2153	$0.2116	$0.2115	$0.2126	$0.2133	$0.2123	$0.2143	$0.2148	$0.2090	$0.2117	$0.2106	$0.2025	
USP Rate Variance	($0.1121)	($0.1162)	($0.0044)	($0.0043)	($0.0043)	($0.0044)	($0.0043)	($0.0043)	$0.0000	$0.0000	$0.0000	$0.0000	
Total Rate R Volumes	1,820	5,329	9,451	10,300	6,699	7,430	4,701	1,124	947	708	684	905	50,100
Total Rate R excl CAP Volumes	1,750	5,120	9,082	9,897	6,437	7,140	4,516	1,079	910	681	658	869	48,139
USP Rate Revenue Variance	($196)	($595)	($40)	($43)	($28)	($31)	($19)	($5)	$0	$0	$0	$0	($958)

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

Adjustment for GPC

	OCT 2017	NOV 2017	DEC 2017	JAN 2018	FEB 2018	MAR 2018	APR 2018	MAY 2018	JUN 2018	JUL 2018	AUG 2018	SEP 2018	TOTAL
GPC Rate FY18- (Weighted Value by District)	$0.0648	$0.0659	$0.0661	$0.0660	$0.0656	$0.0657	$0.0649	$0.0635	$0.0668	$0.0658	$0.0652	$0.0707	
Volume Variance to Historic FY18	(132)	(383)	(632)	(757)	(487)	(544)	(333)	(96)	(70)	(54)	(55)	(65)	(3,609)
Revenue Variance	($9)	($25)	($42)	($50)	($32)	($36)	($22)	($6)	($5)	($4)	($4)	($5)	($237)

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

Adjustment for Interruptibles

Total Unadjusted Interruptble Revenues	$	25,797
Adjustment to Interruptible Revenues @ 40%	$	(10,319)
Adjustment to TCJA for Interruptibles	$	608
Total Interruptible Revenue Adjustment	$	(9,711)

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

Adjustment for Excess Take Revenues

Excess Take (MCF)		(307)
$/MCF	$	6.00
Excess Take Revenue/Margin	$	(1,842)

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

Adjustment for STAS

	Unadjusted 2018 TOTAL	Adjusted 2018 TOTAL	Revenue Adjustment Total
Residential-Non Htg	16	17	1
Residential-Heating	575	599	24
Residential-RT	79	81	2
Total R/RT	670	697	27
Commercial-Non Htg	11	11	0
Commercial- Htg	219	225	6
Commercial-NT	96	99	3
Industrial	11	11	(0)
Industrial-NT	9	9	0
Total N/NT	346	355	9
Total DS	80	82	2
Total LFD	46	47	1
Total XD-F	(24)	(24)	0
Total Interruptible	(9)	(9)	(0)
Grand Total	1,110	1,149	40

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

Adjustment for Get Gas Surcharge

Historic Year 2018	$	78
Historic Year 2018 Annualized	$	96
Get Gas Revenue Adjustment	$	18

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

Adjustment for DSIC

	Unadjusted 2018 TOTAL	Annualized 2018 TOTAL	Revenue Adjustment Total
RES. G	72	75	3
H	3,557	3,312	(244)
SUBTOTAL R	3,629	3,387	(242)
RT	178	219	40
TOTAL	3,808	3,606	(201)
COM. G	72	69	(2)
H	858	815	(43)
SUBTOTAL C-N	930	884	(46)
NT	315	342	26
DS	269	296	27
IS	74	104	30
XD-F	0	0	0
XD-I	56	76	20
LFD	186	274	88
TOTAL	1,829	1,975	146
IND.	65	65	(0)
SUBTOTAL I-N	65	65	(0)
NT	23	27	4
DS	99	102	3
IS	98	186	88
XD-F	0	0	0
XD-I	447	431	(16)
LFD	523	676	153
TOTAL	1,256	1,487	232
GRAND TOTAL	6,892	7,068	176

UGI GAS EXHIBITS DEL-6(a) – DEL-6(c)

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

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	16.3	28,208	459,790
Rate R	15.9	23,992	382,216
Rate RT	18.4	4,216	77,574

Residential Heating

	(1) UPC	(2) Fully Adj	(3) Sales
Total	87.2	564,259	49,203,385
Rate R	87.2	494,385	43,124,347
Rate RT	87.0	69,874	6,079,038
Rate RT Total	83.1	74,090	6,156,612

Commercial Non-Heating

	(1) UPC	(2) Fully Adj	(3) Sales
Total	349.1	4,670	1,630,161
Rate N	217.7	3,224	701,716
Rate NT	503.0	1,408	708,224
Rate DS	5795.3	38	220,221

Commercial Heating

	(1) UPC	(2) Fully Adj	(3) Sales
Total	548.6	63,696	34,943,874
Rate N	340.9	46,589	15,881,877
Rate NT	689.7	15,825	10,914,503
Rate DS	6355.3	1,282	8,147,495
Rate Commercial NT Total	674.4	17,233	11,622,727

Industrial

	(1) UPC	(2) Fully Adj	(3) Sales
Total	3088.3	1,332	4,113,101
Rate N	1067.9	633	675,818
Rate NT	1993.4	465	926,931
Rate DS	10728.0	234	2,510,352
Rate NT Total	709.1	17,698	12,549,658
Rate DS Total	7,000.0	1,554	10,878,068

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

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	16.3	29,715	484,356
Rate R	16.0	25,499	406,782
Rate RT	18.4	4,216	77,574

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	87.6	554,050	48,534,740
Rate R	87.7	484,176	42,455,702
Rate RT	87.0	69,874	6,079,038
Rate RT Total	83.1	74,090	6,156,612

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	349.1	4,709	1,643,912
Rate N	222.5	3,263	726,023
Rate NT	503.0	1,408	708,224
Rate DS	5517.5	38	209,665

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	548.6	62,667	34,379,116
Rate N	337.5	45,560	15,374,681
Rate NT	689.7	15,825	10,914,503
Rate DS	6310.4	1,282	8,089,933
Rate Commercial NT Tota	674.4	17,233	11,622,727

Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	3088.3	1,349	4,166,117
Rate N	1138.0	650	739,715
Rate NT	1993.4	465	926,931
Rate DS	10681.5	234	2,499,471
Rate NT Total	709.1	17,698	12,549,658
Rate DS Total	6,949.2	1,554	10,799,069

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

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	16.3	31,538	514,069
Rate R	16.0	27,227	434,747
Rate RT	18.4	4,311	79,322

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	88.1	541,942	47,745,090
Rate R	88.3	468,479	41,353,809
Rate RT	87.0	73,463	6,391,281
Rate RT Total	83.2	77,774	6,470,603

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	349.1	4,759	1,661,367
Rate N	239.7	3,320	795,773
Rate NT	503.0	1,417	712,751
Rate DS	6947.4	22	152,843

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	548.6	61,466	33,720,248
Rate N	330.0	44,071	14,542,689
Rate NT	689.7	16,173	11,154,518
Rate DS	6565.5	1,222	8,023,041
Rate Commercial NT T	674.7	17,590	11,867,269

Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	3088.3	1,357	4,190,823
Rate N	1339.3	676	905,395
Rate NT	1993.4	462	920,951
Rate DS	10796.7	219	2,364,477
Rate NT Total	708.4	18,052	12,788,220
Rate DS Total	7,204.6	1,463	10,540,361

UGI GAS EXHIBIT DEL-7

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

Current EEC Revenue	$5,765,846	$ 1,321,900	$ (218,944)	$ (81,521)	$ 6,787,281

EEC Increases	Rates R/RT	Rates N/NT	Rate DS	Rate LFD	Total
Incentives	$335,500	$263,600	$184,520	$79,080	$862,700
Administration	$93,898	$43,191	$30,234	$12,957	$180,280
Marketing	$58,000	$8,000	$5,600	$2,400	$74,000
Inspection and Verification	$9,000	$4,000	$2,800	$1,200	$17,000
Evaluations	$620	$0	$0	$0	$620
	$497,018	$318,791	$223,154	$95,637	$1,134,600
Proposed EEC Revenue	$6,262,864	$1,640,691	$4,210	$14,116	$7,921,881
Billing Determinants (Mcf)	49,536,785	29,799,654	10,878,010	21,640,265	
Proposed EEC Rider ($/Mcf)	$ 0.1264	$ 0.0551	$ 0.0004	$ 0.0007	

UGI GAS EXHIBIT DEL-8

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

USP Revenue	$ 8,296,463
USP Billing Determinants (Mcf)	47,598,880
Proposed USP Rate ($/Mcf)	0.1743

Annual Reconciliation Adjustment for CAP Credit and PPA

Combined UGI South and North	2015	2016	2017	3 yr avg
Residential Low Income Write Offs	13.4%	13.8%	8.0%	
Residential Write Offs	3.0%	2.2%	2.5%	
Adjustment (low inc write offs minus residential write offs)	10.4%	11.6%	5.5%	9.2%

UGI GAS EXHIBIT DEL-9

NNS Rate Calculation -- UGI Merged -- Gas Consolidation Base Rate Case 2019

Storage Trip Cost ($/mcf) 0.1315

Weekend Load Reduction Factor (%) 16.4%

WELF = Weekend Load Factor
WD = Weekday Day Use = WE x (1 - WELF)
WE = Weekend Day Use
AVERAGE = Average Daily Use = [(5 x WD) + (2 x WE)] / 7

EQ #1 **WD = (1/(1 - WELF)) * WE**
= (1/(1 - 0.164)) * WE
WD = 1.20 * WE

EQ #2 **AVERAGE = [(5 * WD) + (2 * WE)] / 7**
Step 1 AVERAGE = [5 * ((1/ (1 - WELF)) * WE)) + (2 * WE)] / 7
= [5 * (1/(1 - WELF)) + 2] * WE] / 7
= [5 * (1/(1 - 0.164)) + 2] * WE] / 7
8.00 * WE / 7
Step 2 WE = 0.88 * AVERAGE

EQ #3 **Wkly Imbalance = 5 x (WD - AVERAGE) + 2 (AVERAGE - WE)**
= (5 * WD) - (3 * AVERAGE) - (2 * WE)
= (5 * (1/(1-WELF) * WE) - (3 * AVERAGE) - (2 * WE)
= [(5 * (1/(1-WELF)) + 2) * WE] - (3 * AVERAGE)
= [(5 * (1/(1-0.164)) + 2) * WE] - (3 * AVERAGE)
4.00 * WE - (3 * AVERAGE)
0.52 * AVERAGE

EQ #4 **Unit Cost Calculation ($/mcf)**
= [(Wkly Imbalance) / (7 * AVERAGE)] * STORAGE TRIP COST
= [(0.52 x Average) / (7 x AVERAGE)] x 0.1315
0.07 x 0.1315
0.0092

EQ #5 **Per Unit of Demand Calculation ($/mcf per month)**
= Unit Cost Demand x 20 days
= 0.0092 x 20
0.1840

UGI GAS EXHIBIT DEL-10

MBS Rate Calculation - UGI Gas Merged - Gas Consolidation Base Rate Case 2019

Average Capacity Charge for Storage ($/mcf)	0.6439	(A)
Anticipated Average Monthly Imbalance %	1.5400%	(B)

Load Factors & MBS Rate Calculation

Rate	Load Factor	
DS	28.8%	(C)
LFD	58.9%	(C)
XD Firm	57.6%	(C)
Transportation System Average	50.0%	(D)

MBS Rate Formula

E = [(A / D) - ((A / D) * C)] * B

Rate	MBS Rate ($/mcf)	
DS	0.0141	(E)
LFD	0.0082	(E)
XD Firm	0.0084	(E)

UGI GAS EXHIBIT DEL-11

UGI Utilities, Inc. - Gas Division
Gas Procurement Charge (GPC) Rider Calculation

	Rates R/RT	Rates N/NT	Total
GPC Revenue	$ 2,847,943	$ 1,158,517	$ 4,006,460
GPC Billing Determinants (Mcf)	43,403,360	17,259,182	60,662,542
Proposed GPC Rate ($/Mcf)			$ 0.0660

UGI GAS EXHIBIT DEL-12

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

		Rate R/RT	Rate N/NT
Total Uncollectible Revenue Requirement	$ 11,732,000		
Allocator 1/		94.77%	4.35%
Uncollectible Revenue Requirement		$ 11,118,416	$ 510,342
Total Proposed Revenue		$ 535,760,394	$ 208,998,713
MFC % 2/		2.08%	0.24%

1/ The allocator is based on a 3-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

GET Revenues	Sep-20	Annualized Amount (Sept x 12)
ROI Component of Monthly Surcharge GET Payments (Interest)	$ 23,410.27	$ 280,923.24
Uncollectible & Adder Component of Monthly Surcharge GET Payments	$ 650.27	$ 7,803.24
Uncollectible & Adder Component of Lump Sum Upfront GET Payments	$ 5,802.31	$ 69,627.72
Total	$ 29,862.85	$ 358,354.20

UGI GAS STATEMENT NO. 9 – SHAUN M. HART

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3006814

UGI Utilities, Inc. – Gas Division

Statement No. 9

Direct Testimony of
Shaun M. Hart

Topics Addressed: **Technology & Economic Development Rider**
Energy Efficiency & Conservation Plan Implementation
Large Customer Usage & Revenue Projections
GET Gas Pilot Phase I Report & Phase II Proposal
Daily Metering Expansion Program
Excess Requirement Option Continuation

Dated January 28, 2019

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Shaun M. Hart and my current business address is 1 UGI Drive, Denver, PA, 17517.

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

A. I am employed by UGI Utilities, Inc. ("UGI"), as Director – Major Accounts. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has both a Gas Division ("UGI Gas" or "the Company"), which is a certificated natural gas distribution company ("NGDC"), and an Electric Division ("UGI Electric"), a certificated electric distribution company ("EDC").

Q. What are your responsibilities as Director – Major Accounts?

A. In this position I have overall responsibility for business development and managing customer relationships with UGI's large commercial and industrial gas and electric customers.

Q. Please describe your educational background and work experience.

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

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

A. Yes, I previously provided testimony in the 2011 through 2015 annual Purchased Gas Cost proceedings and the 2012 Gas Procurement Charge proceeding for UGI Gas and its former subsidiaries UGI Central Penn Gas, Inc. ("UGI CPG") and UGI Penn Natural

Gas, Inc. ("UGI PNG"), which were merged into UGI effective October 1, 2018. The former service territories of PNG, UGI Gas, and CPG are now respectively known as the North, South, and Central Rate Districts of UGI Gas. Please see UGI Gas Exhibit SMH-1 for a complete listing of the proceedings in which I have testified and their docket numbers.

Q. What is the purpose of your testimony?

A. In my testimony, on behalf of UGI Gas, I will address the following: (1) continuation and expansion of the Technology and Economic Development ("TED") Rider to the UGI Central Rate District; (2) modifications to the Combined Energy Efficiency and Conservation ("EE&C") Plan, with extension of that program to the UGI Central Rate District; (3) changes to UGI Gas's large customer usage and revenue projections; (4) proposed continuation of the Growth Extension Tariff ("GET Gas") with some modifications to improve the program; (5) Daily Metering Expansion program; and (6) continuation and expansion of the Excess Requirement Option ("ERO") into the UGI North and Central Rate Districts.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring UGI Gas Exhibits SMH-1 through SMH-6. I am also sponsoring certain responses to the Commission's standard filing requirements as indicated on the master list accompanying this filing.

II. TECHNOLOGY AND ECONOMIC DEVELOPMENT RIDER

Q. Is the Company proposing to adopt the TED Rider for the combined gas utility in this proceeding?

A. Yes. Currently, only the tariffs for the North and South Rate Districts of UGI Gas include a TED Rider. The Central Rate District currently does not have a TED Rider. In this proceeding the Company is proposing a common TED Rider that would apply throughout its service territory.

Q. Please explain why the TED Rider is beneficial to UGI Gas's customers and why it should be extended to the entire UGI Gas service territory.

A. Since its inception, the TED Rider has permitted the Company to offer rate flexibility beyond that which is typically permitted in the framework of a regulated natural gas distribution company. This allows the Company to attract new natural gas customers in a way that benefits the distribution system, the Company, and its customers as a whole. Extension of the TED Rider into the Central Rate District will enable the Company to capture additional customers for the benefit of its entire customer base, and not just those in the South and North Rate Districts. In reviewing the merits of the TED Rider, it is first important to understand the function and characteristics of the gas distribution business.

Q. What is the core function of the Company's distribution system?

A. The core function is to transport and distribute natural gas from sources of supply to end-use customers. In the case of UGI Gas, these sources of supply have primarily been delivery points, or the so-called "city gates," of interstate pipeline systems that connect

UGI Gas's distribution system to upstream sources of supply. Other sources of supply include gathering systems, liquefied natural gas facilities, and propane air peaking facilities directly connected to UGI Gas's distribution system. Certain natural gas pipeline systems are or may be constructed through or in close proximity to the UGI Gas distribution system and may also be potential sources of future supply. All current and potential sources of supply can also serve as sources of supply to current or potential UGI Gas customers, some of whom may elect to bypass UGI Gas's distribution system and receive gas directly from these sources.

Q. What are some of the core characteristics of the natural gas distribution business?

A. Two important features of the business are: (1) it is very capital intensive, which is to say that it requires substantial capital costs to provide service to customers; and (2) unlike some other utility services, there are no uses for natural gas for which there are not alternative, substitute forms of energy.

Q. What are some of the consequences of these characteristics?

A. As a result of the capital-intensive nature of the business, it has been recognized since the early days of the industry that the public interest is often best served if NGDCs are granted exclusive service territories so that system costs can be shared by the widest possible customer base in a geographic area. In return for being the sole service provider within a geographic area, however, NGDC rates and services are subject to regulation by the Commission.

Also, as a result of the capital-intensive nature of the business, as well as the general nature of rate regulation, Pennsylvania NGDCs, in accordance with Commission policies, have established provisions in their tariffs incorporating economic tests for the extension of NGDC facilities. Under these tariff provisions, applicants for utility service must pay for the costs of line extensions deemed not to be economic primarily to prevent undue cost shifting to existing customers under traditional ratemaking policies. For some customers, these line extension rules may result in a requirement to make a large up-front payment, or a contribution in aid of construction ("CIAC"), for the extension of facilities. Since some customers may not be willing or able to pay a large up-front CIAC in return for potential long-term savings, a barrier to the expansion of NGDC systems is created. The GET Gas pilot programs currently available in each of the rate districts are designed in an effort to address this problem for some of the residential and small commercial applicants for UGI Gas distribution service, while also protecting the interests of existing customers. The TED Rider is an extension of a similar concept for select commercial and industrial customers.

Q. Does the fact that UGI Gas is the sole entity authorized by the Commission to provide natural gas distribution service throughout its service territory mean that it can dictate the costs under which it would extend its facilities or provide distribution service to customers?

A. No. UGI Gas is subject to Commission oversight and regulation, but is also subject to competitive market forces to a larger degree than other public utilities, such as water or electric utilities. Potential applicants for UGI Gas services and existing UGI Gas customers have alternatives to natural gas. Businesses may choose to locate new or expanding operations elsewhere if the energy costs are attractive enough. Customer characteristics and circumstances, such as tolerance for large up-front CIACs, can also vary considerably. As a result, UGI Gas may lose an applicant's or customer's business, and the associated potential for long-term contributions towards system fixed costs, if it did not have the flexibility to adjust the up-front contribution and/or distribution rates to reflect the applicant's or customer's competitive alternatives. Moreover, these applicants or customers often also bring local economic benefits with expanded utilization of natural gas service by way of direct and indirect jobs, products and services.

Q. Has the Commission historically recognized and made provision in its rate-making policies for the competitive forces UGI faces?

A. Yes. The Commission has, among other things, approved rate case settlements that established TED Riders for the South and North Rate Districts of UGI Gas. The Rider applicable to the South Rate District was approved in the settlement of the UGI Gas base rate proceeding at Docket No. R-2015-2518438. The TED Rider applicable to the North Rate District was approved in the settlement of the UGI PNG base rate proceeding at Docket No. R-2016-2580030. The potential benefit of the TED Rider was highlighted in the Joint Motion of Chairman Brown and Commissioner Sweet accompanying the Order approving the settlement in UGI Gas's last base rate proceeding:

> Lastly, included in the Settlement is a three-year Technology and Development (TED) Rider pilot program. The TED Rider allows UGI commercial customers to negotiate a mutually acceptable contribution in aid of construction amount and distribution rate, so long as, in tandem, they achieve a positive projected net-present value for the utility's investment. This novel pilot proposal should increase access and expand

> the use of natural gas. We commend UGI for including a mechanism which avails larger customers more options to obtain natural gas.

Both TED Riders were approved as “pilots” with three-year terms. The TED Rider for the South Rate District will therefore expire on October 19, 2019 while the TED Rider for the North Rate District will expire on October 20, 2020.

Q. Is the Company proposing to continue the TED Rider as a pilot program?

A. No. Based on the Company’s success with the TED Rider to date, the Company is proposing the TED Rider as a permanent part of the tariff, as opposed to a pilot program. In addition, the Company is proposing to apply the TED Rider to its entire service territory. Currently, the Central Rate District is the only rate district without a TED Rider. As a result of the Company’s proposal, the increased rate flexibility that the TED Rider is already providing in the North and South Rate Districts would apply to potential and existing customers currently in the Central Rate District.

Q. Has increased rate flexibility due to the TED Rider served the public interest and the interests of customers?

A. Yes. Prior to the initiation of the TED Rider, UGI Gas had a measure of rate flexibility to adjust its rates within tariff-specified boundaries to meet changing competitive conditions and customer preferences for firm Rate XD and all interruptible customers. This flexibility contributed to the expansion of UGI Gas’s distribution system and the recovery of fixed costs from a larger customer base. However, UGI Gas had no similar rate flexibility for firm Rate LFD, DS, or N/NT customers.

Since the initiation of the TED Rider in the North and South Rate Districts, UGI Gas has been able to engage in negotiated rate discussions and provide negotiated rates for a larger group of customers. To date, UGI Gas has added three new Rate DS and Rate LFD customers as a result of the TED Rider and six other customers currently in TED Rider negotiations. Moreover, UGI Gas has observed that the existence of the TED Rider allows for more fulsome rate discussions with customers and potential customers. In these instances, even if the customer ultimately elects a non-TED service offering, it has been UGI Gas's experience that the TED Rider has engaged customers in discussions to expand within the UGI Gas distribution territory – discussions which otherwise may not have occurred. UGI Gas is also currently utilizing the TED Rider to provide a lower long-term distribution rate for a customer that installed a Combined Heat and Power ("CHP") facility.

Q. Is the Company providing an analysis of the TED Rider?

A. Yes. Consistent with its reporting requirements for the TED Rider pilots, the Company has developed an analysis of the economic impact of the TED Rider which is attached hereto as UGI Gas Exhibit SMH-2. This analysis shows the revenues associated with TED Rider customers have warranted the Company's investments.

Q. Please describe the TED Rider and associated line extension rules.

A. The TED Rider is currently applicable by request of the applicant and with approval by the Company, and is subject to the following criteria:

1. The Rider is applicable to usage associated with new gas load at competitive risk only.
2. The Rider is applicable for a defined period outlined in the customer's TED Rider service agreement.
3. The Rider is determined and applied using an economic test consistent with UGI Gas's new business extension tariff.

The TED Rider currently permits UGI Gas and an applicant or customer to negotiate a mutually acceptable rider, which could either be: (1) an incremental rate over the otherwise applicable LFD, DS, or N/NT firm service rates; or (2) a rate discount from otherwise applicable LFD, DS, or N/NT firm service rates. The flexibility within the TED Rider would allow for: (i) a lower up-front customer contribution combined with higher negotiated rates; (ii) a larger up-front customer contribution combined with lower negotiated rates; or (iii) in the case of the CHP customer I discussed earlier, flexibility to provide discounted rates as long as the Company's investment is economically justified.

Q. Can you provide an example of how the TED Rider is applied today?

A. Yes. Say a company plans to convert its fleet of vehicles to Compressed Natural Gas ("CNG") vehicles over time, but initially only plans to install compression facilities sufficient to serve a small number of vehicles. The applicant's service location initially would be best served under Rate NT, which, but for a TED Rider or equivalent mechanism, does not offer any opportunity for rate flexibility. If the applicant wants a line extension capable of serving its future needs, but does not have the financial ability to make a large up-front payment for the line extension, the applicant may choose not to proceed with the project. Under the TED Rider, the Company and the applicant could agree to a mutually acceptable incremental distribution rate on top of the Rate NT distribution rate and a reduced CIAC to accommodate the applicant's planned CNG project.

In another instance, a transit agency qualifying for service under Rate DS might receive a grant for the conversion of its fleet to CNG, but still require a temporary discount from the Rate DS distribution rate to help finance the construction of a re-fueling station. Under the TED Rider, the Company and the applicant could agree to a higher CIAC with a mutually acceptable reduction of the DS distribution rate to accommodate the applicant's short-term operating cost targets.

In both of these examples, the overall combination of CIAC payments and distribution rates would still have to justify a Company investment in distribution facilities, consistent with the economic test that UGI Gas applies to line extension requests. The TED Rider thereby reasonably protects the interests of existing customers by avoiding uneconomic investments, while promoting profitable system growth.

Q. Are there any other benefits attributable to the TED Rider?

A. Yes. Customer conversion to natural gas generally displaces the use of less environmentally friendly energy sources in favor of cleaner burning, locally produced natural gas, at a net financial savings to the customer. Therefore, as the TED Rider facilitates adding customers and the expansion of UGI Gas's distribution system, it also benefits the environment, the Pennsylvania economy, and the general public.

Q. Is the Company proposing any changes to the TED Rider?

A. No. The only changes will be to make the existing pilot a permanent tariff rider and to make the TED Rider applicable throughout the Company's service territory. The Company is proposing no programmatic changes. A copy of the TED Rider is contained in UGI Gas Exhibit F.

III. <u>ENERGY EFFICIENCY AND CONSERVATION PLAN IMPLEMENTATION</u>

Q. Has the Company proposed an EE&C Plan in this filing?

A. Yes. Currently, the Company's North and South Rate Districts have an EE&C Plan; the Central Rate District does not have a plan. The Company proposes to implement one EE&C Plan for the entire Company.

Q. Please describe the EE&C Plan.

A. The EE&C Plan will have a five-year timeframe (FY2020 through FY2024). The EE&C Plan consists of a Combined Heat and Power ("CHP") program and the following five natural gas energy efficiency programs:

- Residential Prescriptive (RP)
- Residential New Construction (RNC)
- Residential Retrofit (RR)
- Non-residential Prescriptive (NP)
- Non-residential Custom (NC)

The EE&C Plan is described in further detail in the direct testimony of Theodore M. Love (UGI Gas St. No. 13), senior analyst with Green Energy Economics Group, Inc.

The EE&C Plan Rider is discussed in the direct testimony of Mr. Lahoff (UGI Gas St. No. 8).

Q. How will the EE&C Plan be administered?

A. The EE&C Plan will be managed by the existing internal UGI EE&C team and will be applied throughout the UGI Gas service territory, including the Central Rate District, while today it applies only to the North and South Rate Districts. The EE&C team will oversee program administration performed by Conservation Service Providers ("CSPs") engaged for individual programs. The Company will, where possible, expand the scope of its engagements with its current CSPs to include the Company's total customer base and geographic service territory. This will reduce the ramp-up period ordinarily experienced by a new EE&C Plan and permit the Company to capitalize on the existing programs in the North and South Rate Districts.

Q. How will the EE&C Plan be marketed to customers?

A. UGI Gas will continue its existing marketing of the EE&C Plan. Marketing is focused on relevant, cost-effective communications to drive awareness of EE&C program availability, while also informing customers of the benefits of high efficiency equipment. The marketing efforts will continue to be implemented and managed by UGI internal EE&C Staff, the Company's marketing agency and its CSPs. The EE&C marketing strategy will include, but not be limited to, the following tactics:

1) <u>Company website</u> - Utilize UGI.com to inform customers of energy efficiency and conservation tips, along with applicable programs and associated customer rebates.

2) Social media - Leverage social media (*e.g.*, Twitter, Facebook, etc.) to communicate energy efficiency and conservation messages.

3) Media advertising - Broadcast within the UGI Gas service territory to inform customers of the benefits of energy efficiency and conservation. Advertising may include the following tactics:

   a. Television
   b. Radio
   c. Billboards
   d. Direct mail
   e. Event sponsorship and trade shows

4) Bill inserts/Newsletters - Distribute energy efficiency and conservation tips to customers at a minimum on a quarterly basis. Topics may include:

   a. Seasonal energy conservation tips
   b. Information on low-income assistance programs
   c. Specific rebates available to Residential, Commercial, and Industrial customers

5) CSPs and HVAC Contractors - CSPs and contractors will help identify market opportunities while promoting applicable customer programs and rebates.

Q. How does the Company evaluate the cost effectiveness of the EE&C Plan?

A. The EE&C Plan is evaluated pursuant to the total resource cost ("TRC") test as described in the direct testimony of Mr. Love (UGI Gas St. No. 13). Additionally, the overall economics of CHP projects must meet the line extension provisions of the Company's tariff as well as the TRC test.

Q. Is the Company proposing any changes to the EE&C Plan in this proceeding?

A. Yes, as discussed more fully in the testimony of Mr. Love (UGI Gas St. No. 13), the Company's EE&C Plan is generally modeled on the existing EE&C Plans. However, there are a few modifications. For example, in the current UGI EE&C Plans, Rate DS and Rate LFD customers are only eligible for CHP rebates. The Company is proposing to expand all other non-residential programs beyond N/NT to also include rate DS and LFD customers. Also, the Company proposes not to include the Behavior and Education program in order to prioritize other programs with longer-lived energy savings, and proposes certain program modifications to the Residential Retrofit ("RR") Program.

IV. LARGE CUSTOMER USAGE AND REVENUE PROJECTIONS

Q. Has the Company made any budget adjustments to large customer revenues?

A. Yes, budgeted revenues were adjusted to annualize customer additions and deletions, and to reflect customer changes which were unknown when the 2020 budget was prepared. A further adjustment was made to interruptible revenues, as follows: The budget for interruptible revenues was reduced by 40 percent. Half of this 40 percent reduction (20% of interruptible revenues) would be credited to an Extension and Expansion Fund ("EEF"). The EEF will be used to: (a) lower the otherwise applicable GET Gas surcharge for participating customers; and (b) if an extension or expansion project (be it GET or non-GET) is awarded a grant in accordance with the Commonwealth of

Pennsylvania's Pipeline Investment Program ("PIPE"),[1] provide additional funding as necessary up to the full amount of the grant. The remaining 20 percent of the interruptible revenue reduction would be retained by the Company to incent maximizing interruptible revenues. These adjustments are reflected in the sales and revenue exhibits included in the direct testimony of Mr. Lahoff (UGI Gas St. No. 8). The rationale for the interruptible revenue sharing proposal is presented in the direct testimony of Paul J. Szykman (UGI Gas St. No. 1).

V. GROWTH EXTENSION TARIFF GAS PROGRAM

Q. Please describe the Company's GET Gas Program

A. GET Gas is a five-year pilot program designed to expand the availability of natural gas service in unserved and underserved areas. It provides a means by which certain Rate R/RT and N/NT customers located in designated underserved or unserved geographic areas can obtain natural gas service without paying a CIAC under the Company's main extension tariff. All of the Company's rate districts have a GET Gas tariff, each of which was approved by the Commission in an Order entered on February 20, 2014 at Docket No. P-2013-2356232. The tariffs were filed on June 30, 2014 to be effective on one day's notice. The program began with the connection of the first GET Gas customer on November 4, 2014 and, therefore, the five-year pilot ("GET Gas Phase I") will run through November 3, 2019.

[1] PIPE provides grants to construct the last few miles of natural gas distribution lines to business parks, existing manufacturing and industrial enterprises, which will result in the creation of new economic base jobs in the Commonwealth while providing access to natural gas for residents.

Q. Without GET Gas, how would the Company calculate the CIAC?

A. The Company would calculate the expected revenue from the customer and divide it by a pre-determined rate of return to establish the allowable investment amount. The CIAC would be the difference between the total investment and the allowable investment amount. The CIAC would be the required upfront payment from the customer in order to receive service.

Q. How does GET Gas differ from the standard extension regulations?

A. In lieu of a CIAC, GET Gas customers pay a monthly surcharge for ten years after the initiation of natural gas service. The Company used historical average costs for service lines and mains to project how many customers would be added each year based on the projected total investment of $5.0 million per year per company (as this program was developed when UGI Gas, UGI PNG, and UGI CPG were separate companies) for a total investment target of $75 million. The Company then projected how much of the investment would be supported by the annual base distribution revenue and how much would have to be recovered via the GET Gas surcharge. The GET Gas surcharges were developed on a class basis and GET Gas customers have the option to pay the remaining balance of the GET Gas surcharges as a lump sum upfront payment.

Q. What are the qualifying criteria for Phase I GET Gas projects?

A. Residential and Commercial GET Gas projects must meet all of the following criteria to qualify for the GET Gas program:

- The customer must be located in an "Underserved" or "Unserved Area." An Underserved Area is defined as a small group or pocket of customers located in close proximity to an existing main. An Unserved Area is defined as a portion of a community, town or municipality where the Company has identified significant potential for natural gas service and existing natural gas facilities are located within a reasonable economic distance.
- The capital main cost of the project (for an Unserved or Underserved Area) must be greater than $15,000.
- At least fifty percent (50%) of the prospective customers along the path of the GET Gas facilities are likely to convert their heating source to natural gas within a 12-year period after natural gas facilities are first installed.
- The estimated average extension cost per projected customer cannot exceed $10,000.

Q. Why were these criteria imposed on GET Gas Phase I projects?

A. The $15,000 per project main cost was designed to ensure that GET Gas Phase I would include a manageable number of larger projects as opposed to an unmanageable number of very small projects. The Company limited GET Gas eligibility to projects forecasted to achieve at least fifty percent (50%) market share as a means of keeping the GET Gas surcharge at a reasonable level. The $10,000 per-customer investment limit was set to enable the typical GET Gas customer the opportunity to pay some or all of the monthly charge from the projected savings realized by switching to natural gas. The $10,000 limit was set above the anticipated average investment per customer connected of $7,357 to allow for investment diversity across all GET Gas projects.

Q. What were the Company's assumptions underlying the 50 percent adoption level GET Gas criteria?

A. In Phase I, the Company used market share analysis to determine the reasonableness of the 50 percent adoption level. Such market share analysis included U.S. Census data, direct canvass, UGI historical customer saturation data, and industry data on the useful life expectancy of equipment. Assumptions were different based on the customer's existing heating source as follows:

- For heating oil customers, the estimated number of homes converting from oil to natural gas in year one of each installed project was based on historic conversion rates, with projected conversions for years 2-12 based on the 20-year useful life expectancy of a warm air oil furnace, factoring in the economic advantage of natural gas over oil (the gas-oil spread). The Company therefore estimated that the replacement rate for an oil furnace would be a $1/18^{th}$ per year replacement rate, calculated as follows: (1/18) x (number of oil-heated homes expected to remain after the first year).
- Due to the ease of conversion, improved service reliability and long-term operating costs benefits of natural gas, it was estimated that 100 percent of propane heating sources would convert to natural gas in year one.
- To project electric conversions, the Company assumed a useful life expectancy for electric furnaces of 15 years and, due to the costly conversion of electric

baseboard heat to natural gas furnaces, only fifty percent (50%) of electrically-heated homes were anticipated to convert, resulting in a total projected number of annual electric conversions of: (1/15) x (.5) x (number of electric heating homes).

- Conversions for wood/coal heating sources were assumed at fifty percent (50%) conversion rate over the 12-year period in a ratable fashion as follows: (1/12) x (.5) x (number of wood-coal homes).

Q. What was the basis for the anticipated average investment per customer connected of $7,357?

A. The $7,357 was the average investment based on an anticipated service cost per customer of $2,986 and an anticipated main cost per customer connected of $4,371. The service cost of $2,986 was based on the average conversion customer service cost for the UGI Companies during fiscal year 2012.

Q. How did the UGI Companies derive the main cost component of $4,371?

A. This main cost was developed by a review of 31 sample communities evaluated by the Company as potential GET Gas Unserved Areas. For each of these sample communities, a mapping review was performed in order to: (a) identify the total number of land parcels in the community; (b) calculate the total main footage required to reach all parcels utilizing this data; and (c) calculate an anticipated main construction cost at $33.92 per foot. The Company calculated the main cost per parcel for each community, using the foregoing factors, as follows: (b) multiplied by (c) divided by (a). Next the GET Gas qualifying factors for market share and investment per customer were applied, and those communities having a forecasted market share below fifty (50%) or an anticipated cost per connected customer of greater than $10,000 were dropped from the sample list. From the remaining 18 sample communities, the average main cost per parcel was determined to be $2,404. Dividing the average cost per parcel by a total average attained saturation assumption of fifty-five percent (55%) yielded the $4,371 main cost component used in the GET Gas charge development.

Q. How did the UGI Companies develop the anticipated main construction cost of $33.92 per foot?

A. The $33.92 per foot was the Companies' actual per foot cost for main installed to conversion customers during fiscal year 2012.

Q. Based on these assumptions, what was the Company's projection for GET Gas customer connections during Phase I?

A. The Company anticipated connecting over 10,000 customers over the twelve-year build-out period for GET Gas Phase I.

Q. What was the calculated surcharge for GET Gas customers?

A. As discussed in more detail in the direct testimony of Mr. Lahoff (UGI Gas St. No. 8), and as set forth in Table 1 below, the GET Gas charge is currently set at a different amount for each of the Company's rate districts because they were based, in part, on the average distribution revenue for a typical conversion customer, which currently differs per rate district.

Table 1

Rate District	Rate Schedule	GET Gas Rate
North	R/RT	$44.90/month
	N/NT	$23.01/month plus $2.71 per Mcf for all usage
South	R/RT	$54.95/month
	N/NT	$7.86/month plus $7.37 per Mcf for all usage
Central	R/RT	$21.75/month
	N/NT	$13.08/month plus $1.07 per Mcf for all usage

Q. Was the Company required to report any metrics on the progress of its GET Gas program?

A. Yes. In compliance with the settlement of the GET Gas proceeding (filed November 6, 2013), UGI Gas files an annual report to the Commission including:

- Investment per project broken out by Underserved and Unserved classification;
- Total distance of GET Gas main installed;
- Number of customers connected by project Underserved and Unserved classification;
- Current saturation by project Underserved and Unserved classification;
- GET revenues received by principal and interest;
- Annual GET participant average use per customer by residential and commercial sectors;
- Average GET participant investment cost per customer by residential and commercial sectors;
- The number of customers along GET facilities who have not yet connected and, to the extent available, why;
- Direct program expenses;
- Data on collections, including efforts for unpaid surcharge amounts;

- The number of applicants turned down for insufficient credit;
- The number of GET Gas participants also participating in CAP; and
- The quarterly gas/oil spread differential.

Q. Has the Company been meeting this reporting requirement?

A. Yes. Please see UGI Gas Exhibit SMH-3 for the Company's most recent GET Gas report.

Q. What has been the Company's experience during the first four years of GET Gas Phase I?

A. Through November 30, 2018, the Company has extended service to 585 residential customers and four (4) commercial customers and is forecasting approximately 9,084 additional customers in GET Gas projects that are currently underway or have been committed to by the Company. The Company has spent approximately $19.1 million to date and is forecasted to spend approximately $22.4 million more by the end of the pilot on November 3, 2019. For each project begun during the five-year term of GET Gas Phase I, the Company projects to spend $7,553 per customer, which factors in the cost expended and customers added during the twelve-year post-in-service date.

The Company's experience over the past four years confirms that high cost is a barrier to natural gas conversion. In a survey the Company conducted in October 2018, 82% of those surveyed expressed that the high cost associated with the GET Gas surcharge in addition to equipment conversion costs were the primary reasons for not converting to natural gas. *See* UGI Gas Exhibit SMH-4. This is further demonstrated by the higher market share in the rate district with the lowest surcharge, which I will describe in more detail below. The Company has also determined that approximately 62% of GET Gas customers pay off their GET Gas balance within three years of connecting to gas. During the first four years of GET Gas Phase I, the price differential between heating oil and natural gas has narrowed, resulting in a lower overall savings incentive for potential customers to participate in a GET Gas project. While natural gas is still a more economic option for home heating, this decrease in the oil-gas spread has removed some of the financial incentive for customer conversions.

Increases in costs related to municipal permitting and restoration requirements were also observed to be a significant factor in a GET Gas project's success. Projects installed in municipalities with permitting and restoration costs that do not exceed PennDOT requirements tend to more easily qualify for the project selection criteria outlined earlier in my testimony. Where municipal requirements, *e.g.*, the cost of road entry permits and street restoration requirements, exceed the PennDOT standard, the Company is largely unable to construct the project within the existing criteria. In several cases, Company resources have been expended in evaluating projects that have not come to fruition based on excessive municipal requirements.

Community support for the project was also helpful for the project to be successful, whether in the form of a positive lower-cost construction environment, like the municipal road access costs I touched on earlier, or by way of having individual neighbor support for the projects. Where a close-knit community supported the project, greater market share was generally achieved. Where municipalities held public meetings to give UGI representatives and community members the ability to interact, pose questions and discuss the publicly touted benefits of the project, the likelihood of a project's success increased.

Q. What is the Company's current forecast for the end of the fully projected future test year ("FPFTY") ending September 30, 2020?

A. The Company is forecasting a total of approximately $73.1 million of capital spend over the 12-year build-out of the GET Gas projects that are currently underway or expected to commence during the five-year pilot. This would include extending service to approximately 9,673 customers for an average cost of approximately $7,553 per customer. Of this $73.1 million, $15 million is forecasted to be spent in the FPFTY. The capital budget is discussed in the direct testimony of Hans G. Bell (UGI Gas St. No. 2).

Q. Has the Company made any adjustments to its Phase I plan in response to its experience over the first four years of the pilot?

A. Yes. In order to address lower than expected initial market share, primarily due to a narrowed gas-oil spread, the Company initiated an 8-step customer notification and marketing process. The process includes a consistent approach from initial canvassing, to in person door-to-door canvassing, door-hangers, postcards, FAQs, tailgate sessions, construction notifications, and finally a thank you gift for all homes along the route. Specific marketing programs targeting non-converters with initial interest along GET Gas routes are ongoing via e-mail and mail. Non-converters who have not shown any initial interest are more difficult to contact, due to a lack of contact information. Periodic postcards are mailed to existing projects to keep gas availability at the top of mind.

Additionally, the Company has redesigned the GET Gas webpage and has plans to further automate digital campaigns targeting approximately 750 homeowners who have provided their contact information, but have not yet committed to receiving natural gas service.

Further, the Company responded to the development of the GET Gas program by reorganizing some internal resources. As Phase I projects matured and more and more projects were evaluated, it became evident that these projects needed to be evaluated by a distinct group of engineers and communications and sales staff, since GET Gas projects share similar characteristics and constraints. One example of this internal reorganization was the establishment of a dedicated engineering group to work specifically on GET Gas projects.

Q. Does the Company intend to further modify the program in Phase II?

A. Yes. While the Company will maintain the qualifying criteria for GET Gas projects (Underserved/Unserved Areas; $15,000 per-project minimum; $10,000 maximum per customer cost; fifty percent (50%) market share), other aspects of project management will be changed to increase market share. Based on our experience during Phase I, the Company will no longer prioritize Underserved GET Gas projects based on when the first conversion inquiry is received. Rather, the Company will apply the same methodology used for Unserved GET Gas projects today, which is based on strong customer and municipal support as well as economic feasibility, to prioritize Underserved GET Gas projects. The Company will also no longer restrict investment based on an attempt to evenly fund Underserved and Unserved Areas. The Company will instead pursue all

GET Gas projects, whether they are to serve an Underserved or Unserved Area, based on strong customer and municipal support and economic feasibility.

Q. Is the Company proposing to adjust the GET Gas customer charges in this filing?

A. Yes. The Company agreed as part of its settlement of the GET Gas proceeding, that if it filed a general base rate case during the term of the pilot, it would 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: (1) revenue from a base rate increase; (2) annual sales volumes; (3) average use per customer for GET Gas customers; (4) depreciation rates; (5) weighted cost of debt; (6) return on equity; (7) tax rates; (8) CAP component; and (9) uncollectibles component. The Company has recalculated the charge accordingly. Also, the Company is proposing to modify the commercial surcharge, which, in Phase I was composed of a fixed commercial surcharge with a reduced volumetric charge. As a result of the Company's proposed single distribution rate structure in this rate case proceeding, the GET Gas rate will be the same company-wide for all GET Gas customers. However, based on the Company's experience to date with the diversity of end use and customer conversion economics in the commercial market segment, rate flexibility is key to incentivizing commercial customers to convert to natural gas. Therefore, the TED Rider will be relied upon to optimize commercial growth opportunities along GET Gas mains on a case by case basis.

Q. Please explain the assumptions underlying the proposed Phase II GET Gas rate.

A. The assumptions underlying the GET Gas Phase II charge are the same as those upon which the GET Gas Phase I charge were based except as outlined in UGI Gas Exhibit SMH-5. Specifically, the use of an Extension and Expansion Fund supported by interruptible customer revenue sharing will keep the GET Gas surcharge at a level that should incent residential conversions to natural gas. With a lower GET Gas surcharge, the Company anticipates achieving its 50 percent market share target. Due to the creation of the EEF, the residential GET Gas surcharge will be $21.75 per month and the commercial GET Gas surcharge will be $7.86 per month with a volumetric surcharge of $1.07 per Mcf. The calculation of the new GET Gas rate is further described in the direct testimony of Mr. Lahoff (UGI Gas St. No. 8).

Q. How would this rate change impact the GET Gas customers who are already signed up with the program?

A. As set forth in paragraph 21 of the GET Gas settlement agreement, existing GET Gas customers will pay the lower of the Phase I surcharge or Phase II surcharge for the remaining term of the GET Gas surcharge. Because the Phase II GET Gas surcharge is being set at $21.75 per month for residential and $7.86 per month with a volumetric surcharge of $1.07 per Mcf for commercial, all Phase I GET Gas customers will benefit from either the same or a lower surcharge.

Q. Is the Company proposing to continue GET Gas as a pilot?

A. Yes. The Company is proposing to extend the term of the combined GET Gas pilot for five years. Despite actual market share results that, to date, are less than forecasted due to a variety of factors stated earlier, the Company believes that the program has been a success and the Company anticipates that it will meet its fifty percent (50%) market share projection by the end of the 12-year buildout of Phase I with the changes it is proposing, including the use of an EEF to lower the GET Gas surcharge. This program has been recognized by the Commission as an innovative way to bring more energy choices to unserved and underserved communities. However, the Company recognizes that an additional period of analysis is warranted. The Company's initial assumptions were based on adoption during the 12-year build-out of Phase I of GET Gas. As the Company is only four years into this program, it would be premature to make this a permanent provision of the Company's tariff.

VI. <u>DAILY METERING EXPANSION</u>

Q. What are the Company's plans for expanding the use of daily metering?

A. Currently, not all of the non-choice transportation customers in the South Rate District have daily metering of gas usage, while every non-choice transportation customer in the North and Central Rate Districts do have daily metering. This mismatch arose approximately 30 years ago at the outset of transportation service for smaller transportation customers in the South Rate District, when daily metering facilities were not a condition of transportation service. Thus, as of November 30, 2018, UGI Gas has 1,439 meters associated with non-choice transportation customers without daily metering capabilities. Pursuant to Section 5.7 of the Company's Tariff for the South Rate District, the Company reserves the right as a condition of service to install daily metering facilities at every meter served under a non-choice transportation rate schedule. Based on the potential benefits to customer choice discussed below, the Company proposes a schedule for the installation of daily metering facilities for all non-choice transportation customers and to thereafter transfer all non-choice transportation customer accounts to calendar month billing and balancing pools.

Q. How does transportation customer billing work today without daily meter capability for non-choice transportation customers?

A. For Rate LFD and XD customers without daily meter capability on certain meters, the Company reads these meters at the end of each calendar month and this monthly usage is converted to daily usage as a simple average across the days in the month and added to their automated daily meter reads so these customers can be daily balanced and billed by calendar month. On the other hand, Rate IS and DS customers without daily metering facilities have their meters read on a monthly basis in customer groups on so-called “Work Days” throughout the month. This meter read data is then used to generate customer account bills which are issued throughout the month on an intra-month basis.

Q. Why is the Company proposing to install the daily metering facilities for these customers?

A. Installing daily metering facilities for these customers would allow them to be pooled with other transportation customers who are billed on a calendar month cycle. Customer accounts served by natural gas suppliers (“NGS”) are almost always, at the request of the NGS, grouped into customer billing pools pursuant to Section 20(h) of the Company’s Tariff for the South Rate District. The use of billing pools enables the NGS to nominate gas supplies and to balance gas deliveries with consumption on a pool-wide, rather than an individual customer account, basis. This is not possible for UGI South customers without daily metering. The expansion of daily metering would facilitate customer choice by making it easier for NGSs to manage all customer pools on a calendar month basis on UGI Gas's system.

Q. What is the cost associated with this expansion of daily metering?

A. The Company estimates a cost of approximately $2.7 million with associated annual operating and depreciation expenses of approximately $0.6 million as set forth in UGI Gas Exhibit SMH-6. The Company proposes to recover the costs of installation, associated expenses, and a return on and of its capital investment in base rates. The adjustment to the budget due to this expansion of daily metering facilities is addressed in the direct testimony of Stephen F. Anzaldo (UGI Gas St. No. 3).

Q. Is there a customer impact to this daily metering expansion?

A. Yes. Rate DS customers in the South Rate District will be required to have a Maximum Daily Quantity ("MDQ") defined in their service agreements. These MDQs will be calculated by the Company and communicated to the customers 60 days prior to the end of the FPFTY. The communication will state that customers will have the opportunity to elect an MDQ different from the Company's calculation by providing that MDQ to the Company no later than 30 days prior to the effective date of the MDQ. The Company will review any alternate MDQ election for reasonableness and will communicate the result of such review and work with the customer to achieve a mutually agreeable MDQ. The Company's "reasonable" standard and its requirement to provide 30 days' notice to change an MDQ election are consistent with how the Company amends MDQs for current Rate DS customers in the North and Central Rate Districts.

VII. EXCESS REQUIREMENT OPTION

Q. Is the Company proposing to expand its ERO offering in this proceeding?

A. Yes. Currently, the South Rate District tariff includes ERO, but the North and Central Rate Districts do not have ERO. In this proceeding the Company is proposing a common ERO that would apply throughout its service territory.

Q. Please explain why ERO is beneficial to South Rate District customers and why it should be extended to the entire UGI Gas service territory.

A. As stated in the tariff, ERO is an option available on an interruptible basis to any Rate XD or LFD customer to extend the no-notice provisions of Rate NNS, on a best efforts basis, during periods where the customer's daily requirements exceed their contractual Daily Firm Requirement ("DFR"). ERO is limited to 25 percent of a customer's DFR and provides protection against otherwise applicable Excess Take Charges for DFR overruns. ERO has been an option available to Rate LFD and XD customers in the current South Rate District since at least 1995. In an effort to consolidate and standardize the Company's tariff, rather than remove ERO for South Rate District customers who have been relying on it for many years, the Company has proposed to continue ERO and make it an available option for all Rate XD and LFD customers.

Q. Does that conclude your testimony?

A. Yes, it does.

UGI GAS EXHIBIT SMH-1

Shaun M. Hart
Director – Major Accounts

Work Experience

2017 – present	Director – Major Accounts UGI Utilities, Inc., Reading, PA
2015 – 2017	Manager – Major Accounts UGI Utilities, Inc., Reading, PA
2010 – 2015	Manager – Supply UGI Utilities, Inc., Reading, PA
2008 – 2010	Manager, Natural Gas Trading UGI Energy Services, Inc., Wyomissing, PA
2005 – 2008	Supply Analyst UGI Energy Services, Inc., Wyomissing, PA
2003 – 2005	Application Systems Analyst UGI Energy Services, Inc., Wyomissing, PA

Previous Testimony

1307(f) proceedings:	Docket Nos. R-2015-2480950, R-2015-2480934, R-2015-2480937, R-2014-2420273, R-2014-2420276, R-2014-2420279, R-2013-2361763, R-2013-2361764, R-2013-2361771, R-2012-2302219, R-2012-2302220, R-2012-2302221, R-2011-2238943, R-2011-2238949, R-2011-2238953
GPC proceedings:	Docket Nos. R-2012-2314224, R-2012-2314235, R-2012-2314247

Education

M.B.A. from Villanova University, 2012
B.S. in Computer Science from Penn State University, 2003

UGI GAS EXHIBIT SMH-2

TED Rider Economics

A. Project Costs ('000)	$	6,034	
B. CIACs ('000)	$	180	
C. Net Project Costs ('000)	$	5,854	C = A - B
D. Annual Tariff Revenue ('000)	$	429	
E. Annual TED Rider Revenue ('000)	$	513	
F. Total Annual Revenue ('000)	$	942	F = D + E
G. Simple Payback (years)		6.2	G = C / F
H. Annual Tariff Revenue at Proposed Rates			
I. Excess Revenue ('000)			I = F - H

UGI GAS EXHIBIT SMH-3

Energy to do more®

UGI Utilities, Inc.
2525 N. 12th Street
Suite 360
PO Box 12677
Reading, PA 19612-2677

Becky Eshbach
Director – Marketing Programs & Strategies

VIA FEDERAL EXPRESS

November 1, 2018

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, Pennsylvania 17120

Re: Joint Petition of UGI Utilities, Inc. – Gas Division, UGI Penn Natural Gas, Inc. and UGI Central Penn Gas, Inc. For Approval To Implement Growth Extension Tariff Pilot Programs To Facilitate The Extension of Gas Service To Unserved and Underserved Areas Within The Companies' Service Territories (Annual Report), Docket No. P-2013-2356232

Dear Secretary Chiavetta:

In the above-captioned proceeding the UGI Distribution Companies ("UGI Companies"), comprised for purposes of the filing of UGI Utilities, Inc. – Gas Division ("UGI"), UGI Penn Natural Gas, Inc. ("PNG") and UGI Central Penn Gas, Inc. ("CPG"), sought Commission approval of a Growth Extension Tariff ("GET Gas") Pilot program, and stated in their petition that they would "provide annual reports to the Commission describing program spending, customers connected and other key indicators." Thereafter, in a Commission Order entered on February 20, 2014, the Commission approved a Joint Petition for Approval of Settlement of All Issues under which the UGI Companies agreed, in pertinent part:

18. The UGI Companies will add the following items to the proposed annual reporting (to begin 12 months after the first GET Gas customer is connected), to the extent not already contemplated:

(a) Investment per project broken out by Underserved and Unserved classification;

Energy to do more®

(b) Total distance of GET Gas main installed;

(c) Number of customers connected by project Underserved and Unserved classification;

(d) Current saturation by project Underserved and Unserved classification;

(e) GET revenues received by principal and interest;

(f) Annual GET participant average use per customer by residential and commercial sectors;

(g) Average GET participant investment cost per customer by residential and commercial sectors;

(h) The number of customers along GET facilities who have not yet connected and, to the extent available, why;

(i) Direct program expenses;

(j) Data on collections, including efforts for unpaid surcharge amounts;

(k) The number of applicants turned down for insufficient credit;

(l) The number of GET Gas participants also participating in CAP; and

(m) The quarterly gas/oil spread differential pursuant to proposed tariff sections 5.8.4 Limitations (UGI) and 5.9.4 Limitations (PNG and CPG).

Should you have any questions concerning these reports please feel free to contact me.

Respectfully submitted,

Becky Eshbach
Director Marketing Programs & Strategies

Enclosure

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Joint Petition of UGI Utilities, Inc. – Gas Division, UGI Penn Natural Gas, Inc. and UGI Central Penn Gas, Inc. For Approval To Implement Growth Extension Tariff Pilot Programs To Facilitate The Extension of Gas Service To Unserved and Underserved Areas Within The Companies' Service Territories	:	Docket No. P-2013-2356232

CERTIFICATE OF SERVICE

I hereby certify that I have, this 1st day of November 2018, served a true and correct copy of the foregoing document in the manner and upon the persons listed below in accordance with requirements of 52 Pa. Code §1.54 (relating to service by a participant):

VIA FIRST CLASS MAIL:

Office of Consumer Advocate
5th Floor, Forum Place
555 Walnut Street
Harrisburg, PA 17101-1921

Office of Small Business Advocate
Suite 202, Commerce Building
300 North Second Street
Harrisburg, PA 17101

Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Becky Eshbach

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Joint Petition of UGI Utilities, Inc. – Gas	:	
Division, UGI Penn Natural Gas, Inc. and	:	
UGI Central Penn Gas, Inc. For Approval	:	
To Implement Growth Extension Tariff	:	
Pilot Programs To Facilitate The	:	Docket No. P-2013-2356232
Extension of Gas Service To Unserved	:	
and Underserved Areas Within The	:	
Companies' Service Territories	:	
	:	

ANNUAL GET GAS REPORT

I. Introduction:

Since approval by the Commission, the UGI Companies' GET Gas Pilot program has installed gas main in 87 GET Gas projects and connected 499 new customers. As UGI completed the fourth year of the pilot program, a number of changes were made to streamline and improve the GET Gas program including:

- Realigning the sales organization to facilitate the most streamlined approach to processing leads and evaluating the validity of proposed projects.
- Improving the marketing approach for GET Gas including partnerships with HVAC providers, community outreach in the form of informal meet and greets, sweepstakes to help homeowners offset the cost of equipment and thank you gifts to show appreciation to homeowners along construction paths.

Barriers to the program are:

- Reduced oil pricing since the beginning of the pilot causing a lower natural gas price spread (see Exhibit 3).
- Continued barriers in some territories created by local municipal permitting and restoration requirements, or changed costs related to same.
- A mild 2018 winter

The UGI Companies' future plans for GET Gas at this time have 71 projects slated through 2019 with related GET Gas investment amounts of over $25 million.

II. Report:

Program spending and customers connected

See Introduction and responses below. Where appropriate, data from fiscal year 2015, 2016, 2017 and 2018 are shown.

a. **Investment per project broken out by Underserved and Unserved classification**

Total investment for projects completed for FY 2018 was $4,326,499 with $546,979 spent for projects still in-progress for a total of $4,873,477.
See Exhibit 1, Column K

b. **Total distance of GET Gas main installed**

A total of 33,782 feet of main was installed for FY 2018 completed projects with a total of 240,367 feet installed since program inception.
See Exhibit 1, Column E

c. **Number of customers connected by project Underserved and Unserved classification**

A total of 38 customers connected to mains installed in FY 2018 with 460 customers connecting to mains installed in FY 2015 - 2017 for a total of 499 customers since program inception. In addition, 125 homeowners have committed to participate by signing a customer agreement letter and are currently awaiting service and/or meter installation.

Four commercial customers have been added to-date and are included in the aforementioned counts.
See Exhibit 1, Column H and I

d. **Current saturation by project underserved and unserved classification**

Since program inception, the current market share for completed projects is 8% (498 customers/6,581 parcels).
See Exhibit 1, Column J

e. **GET Revenues received by principal and interest**

Since program inception GET revenues received have been $988,856 from principal and $92,776 from interest/adder for a total of $1,122,488.
See Exhibit 2

f. Annual GET participant average use per customer by residential and commercial sectors

The average annual usage for residential GET customers with 12 months of available usage data is 689 ccf.

Average usage for the commercial GET customers that had with at least 12 months of available usage was 2122 ccf.

g. **Average GET principal investment cost per customer by residential and commercial sectors**
Since the program inception, the average cost per customer for completed projects = $31,936 ($15,904,072/498). The difference in cost investment between residential and the four commercial customers is negligible. See Exhibit 1, Columns K, H and I.

Note: Cost per customer will decrease as additional customers are added through the life of GET project. Projected cost per customer is $8,926 ($78,962,056/8,846).

h. **The number of customers along GET facilities who have not yet connected and, to the extent available, why**
Total Parcels for all the completed FY 2015 - FY 2018 projects is 5,699. Projected GET customers, the anticipated number of customers based on market share model, for all completed projects is 3,454 with 2,956 not yet converting.

i. **Direct program expenses**
$ 41,598 FY2018
NOTE: Marketing expenses included development and printing of marketing materials, promotional events and giveaways.

j. **Data on collections, including efforts for unpaid surcharge amounts**
As of 10/23/18, 18 customers have an overdue balance ($8,033) of which there are uncollected surcharges from 15 customers in the amount of $4,763.

The GET Gas past due amounts fall outside of PUC regulations and therefore cannot be used as a trigger for shut off. The current collections process for overdue surcharge amounts involves manual collection efforts with the possibility of submitting a file to a third party collections agency. All customers are required to submit a deposit if they do not meet credit guidelines or a minimum credit score obtained by Experian.

k. **The number of applicants turned down for insufficient credit**
No applicants were turned down for insufficient credit.

l. **The number of GET Gas participants also participating in CAP**
There are no GET customers enrolled in CAP at this time.

m. **The quarterly gas/oil spread differential pursuant to proposed tariff sections 5.8.4 Limitations (UGI) and 5.9.4 Limitations (PNG and CPG).**
See Exhibit 3

Exhibits

Exhibit 1. GET Gas Projects Customers and Costs

Note: All projects will incur costs as services are added toward the life of GET project (12 years).

COMPANY	PROGRAM YEAR	TYPE	PROJECT NAME	INSTALLED MAIN (FT)	PARCELS	PROJECTED GET CUSTOMERS MODEL	GET RESIDENTIAL CUSTOMERS	GET COMMERCIAL CUSTOMERS	[illegible]AL MARKET SHARE	PROJECT COST-TO-DATE FY 2015-2018
A	B	C	D	E	F	G	H	I	J	K
PROJECTS COMPLETED - 2015										
2015 COMPLETED PROJECTS			14	41,312	603	333	116	1	15%	2,187,857
PROJECTS COMPLETED - 2016										
2016 COMPLETED PROJECTS			21	102,304	1,693	1,100	212	-	13%	$ 4,920,550
PROJECTS COMPLETED - 2017										
2017 COMPLETED PROJECTS			26	62,869	1,783	1,044	128	4	7%	$ 4,468,166
PROJECTS COMPLETED - 2018										
UGI	2018	UNDERSERVED	Beech	1,200	21	12	1	-	5%	$ (53,777)
UGI	2018	UNDERSERVED	Brinser	4,376	71	39	-	-	0%	$ 220,534
UGI	2018	UNDERSERVED	Conestoga	4,092	142	78	4	-	3%	$ (510)
UGI	2018	UNDERSERVED	Kathryn	885	43	24	-	-	0%	$ 265,762
UGI	2018	UNDERSERVED	KENWOOD	-	223	123	6	-	3%	$ 367,954
UGI	2018	UNDERSERVED	King	530	5	3	-	-	0%	$ 29,631
UGI	2018	UNDERSERVED	Martin	9,000	142	92	-	-	0%	$ 148,211
UGI	2018	UNDERSERVED	Oregon	1,030	19	11	-	-	0%	$ 60,067
UGI	2018	UNDERSERVED	Tilghman	1,906	22	14	-	-	0%	$ 98,746
UGI	2018	UNDERSERVED	W Highland	1,125	20	12	-	-	0%	$ 59,144
UGI	2018	UNDERSERVED	Wheatland	4,400	39	25	-	-	0%	$ 157,691
UGI	2018	UNDERSERVED	Gralan	4,633	54	30	-	-	0%	$ 206,143
UGI	2018	UNDERSERVED	White Acre	4,000	23	13	1	-	4%	$ 124,176
UGI	2018	UNDERSERVED	Maplewood	2,900	47	29	-	-	0%	$ -
UGI	2018	UNSERVED	ECH PH1	-	94	57	3	-	3%	$ 332,240
UGI	2018	UNSERVED	ECH PH2	-	76	46	-	-	0%	$ 125,311
PNG	2018	UNDERSERVED	Mulberry	-	28	17	5	-	18%	$ 63,730
PNG	2018	UNDERSERVED	Shirley	2,203	27	15	-	-	0%	$ 63,952
PNG	2018	UNDERSERVED	Crestwood	3,876	50	28	-	-	0%	$ 176,014
PNG	2018	UNSERVED	DUPONT	-	95	72	3	-	3%	$ 444,251
PNG	2018	UNSERVED	Riverside PH3	-	158	89	4	-	3%	$ 767,698
CPG	2018	UNDERSERVED	ARNOLD	3,238	56	37	8	-	14%	$ 128,869
CPG	2018	UNDERSERVED	CLINTON	3,996	44	30	3	-	7%	$ 140,617
CPG	2018	UNDERSERVED	Cumberland	2,800	46	31	-	-	0%	$ 125,169
CPG	2018	UNDERSERVED	Martin	3,450	45	31	-	-	0%	$ 148,211
CPG	2018	UNDERSERVED	Laurie	1,909	29	19	-	-	0%	$ 125,667
2018 COMPLETED PROJECTS			26	61,432	1,626	877	38	-	4%	4,328,489
ALL COMPLETED PROJECTS				268,817	5,999	3,454	494	5	8%	15,945,072
PROJECTS IN PROGRESS - 2018										
UGI	2018	UNDERSERVED	Fish Hatchery	-	127	67	-	-	0%	$ 26,565
UGI	2018	UNDERSERVED	Stafore	-	84	45	-	-	0%	$ 20,701
UGI	2018	UNDERSERVED	Hillside	-	91	51	-	-	0%	$ 38,375
UGI	2018	UNDERSERVED	Sarhelm	-	111	60	-	-	0%	$ 315,632
UGI	2018	UNDERSERVED	Glenn	-	48	26	-	-	0%	$ 6,018
UGI	2018	UNSERVED	Meadow Creek	-	70	39	-	-	0%	$ 14,862
UGI	2018	UNSERVED	Woodridge	-	89	49	-	-	0%	$ 17,969
CPG	2018	UNDERSERVED	Saint Paul 2	-	50	27	-	-	0%	$ 5,469
CPG	2018	UNDERSERVED	Sunnyside	-	158	63	-	-	0%	$ -
CPG	2018	UNDERSERVED	Hickory	-	54	30	-	-	0%	$ 100,388
2018 PROJECTS IN PROGRESS				-	882	457	-	-	0%	$ 546,979
Blanket Services										$ 1,255,371
GET TOTAL FOR ALL PRO				268,817	6,881	3,911	494	5	8%	17,746,422

Exhibit 2. GET Principal and Interest Received

CUSTOMER TYPE		PRINCIPAL	INTEREST AND UNCOLLECTIBLE ADDER	TOTAL REVENUE	TOTAL CUSTOMERS	REVENUE PER CUSTOMER
Residential	UGI	$ 760,008	$ 89,655	$ 849,663	326	$ 2,606
	PNG	$ 163,051	$ 38,362	$ 201,413	108	$ 1,865
	CPG	$ 60,153	$ 5,098	$ 65,252	60	$ 1,088
Total		$ 983,212	$ 133,115	$ 1,116,327	494	$ 2,260

CUSTOMER TYPE		PRINCIPAL	INTEREST AND UNCOLLECTIBLE ADDER	TOTAL REVENUE	TOTAL CUSTOMERS	REVENUE PER CUSTOMER
Commercial	UGI	$ 3,082		$ 3,082	2	$ 1,541
	PNG	$ 2,562	$ 517	$ 3,079	3	$ 1,026
	CPG	$ -	$ -	$ -	-	$ -
Total		$ 5,644	$ 517	$ 6,161	5	$ 1,232

CUSTOMER TYPE		PRINCIPAL	INTEREST AND UNCOLLECTIBLE ADDER	TOTAL REVENUE	TOTAL CUSTOMERS	REVENUE PER CUSTOMER
Total	UGI	$ 763,090	$ 89,655	$ 852,745	328	$ 2,616
	PNG	$ 165,613	$ 38,879	$ 204,492	111	$ 1,893
	CPG	$ 60,153	$ 5,098	$ 65,252	60	$ 1,088
Total		$ 988,856	$ 133,632	$ 1,122,488	499	$ 2,272

Exhibit 3. Quarterly Gas Oil Spread for FY 2018

DATE	COMPANY	PRICE SPREAD($/MMBtu)	
DEC 1 2017	UGI	$	7.51
	PNG	$	9.38
	CPG	$	6.33
MAR 1 2018	UGI	$	8.26
	PNG	$	9.51
	CPG	$	7.08
JUNE 1 2018	UGI	$	10.14
	PNG	$	11.09
	CPG	$	8.97
SEP 1 2018	UGI	$	10.09
	PNG	$	11.03
	CPG	$	8.92

UGI GAS EXHIBIT SMH-4

Energy to do more®

GET Gas

GET Gas Leads Survey

October 2018

Methodology

Energy to do more®

- Residential leads in existing GET Gas projects
- Status “Considering”, “Declined” or “Needs to be Updated”
- GET Gas project “Closed” or “Completed”
- Sep – 213 leads, 18 bounced, 64 responses (30%), 57 qualified, 9/24/18-10/3/18
- Error margin for all responses at 95% confidence is ±11%
- Email address on file
- Qualified respondents (not a customer, decision-maker) who completed the survey received a $5 Amazon gift code
- Purpose of survey is to measure awareness of GET Gas program, identify interest level and barriers to conversion

Key Findings

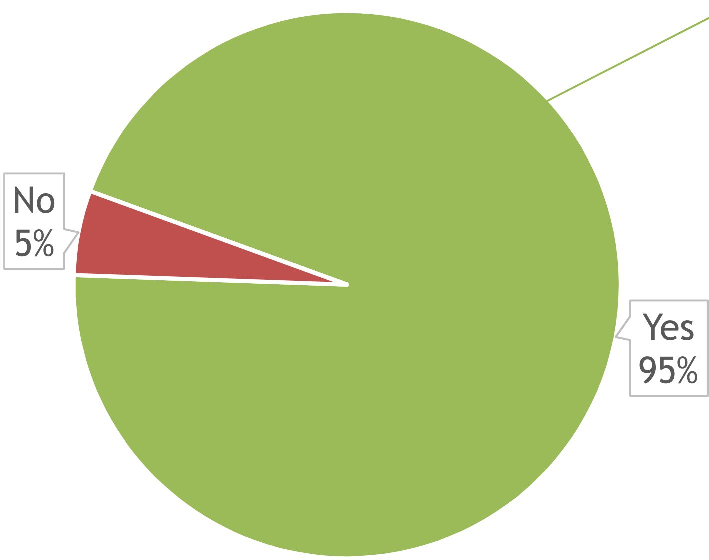
Energy to do more®

- Cost is the primary barrier to conversion via GET Gas
- Awareness that natural gas is available is not an issue
  - In fact, nearly all homeowners considered converting but were deterred by the GET Gas surcharge amount
- The GET Gas brand name is not well known, but what the program offers is understood by more than half of homeowners
- One in four said they are interested in converting to natural gas via the GET Gas program using the monthly payment option with an additional 16% interested in the upfront payment option
  - One in four said they will not consider converting to natural gas via GET Gas while 32% are unsure
- Homeowners said a payback period of 2-5 years is optimal

Awareness

- Nearly all homeowners (leads) in existing GET Gas projects are aware that natural gas is available to them
- Most became aware when they saw UGI during construction or they recall seeing something in the mail

Aware gas is available? n=57



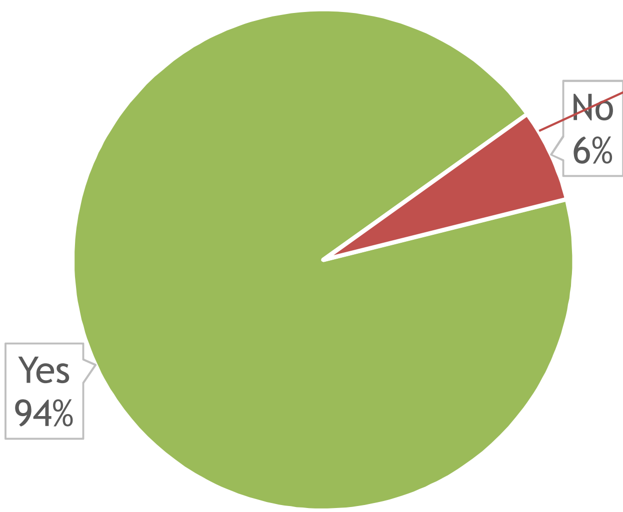
How did you become aware that gas is available? n=54

- 65% • Saw UGI during construction
- 41% • Received info in mail from UGI
- 22% • Heard from a neighbor
- 19% • UGI rep contacted me
- 7% • HVAC Contractor contacted me
- 7% • I contacted UGI
- 4% • Saw something in the news

Consideration of GET Gas

- Almost all homeowners (leads) did consider switching to natural gas when it became available but they did not due to costs – the connection fee is considered excessively high

Consider switching when gas became available? n=54



Why didn't you switch to natural gas? n=50

82%	• Cost is too high/Too expensive
8%	• Timing/Not ready
6%	• Waiting for equipment to break
4%	• Didn't receive response from UGI

"Hook up fee was too high. "

"Cost to get gas line to property was ridiculously high. It would take over 10 years to break even versus continuing to use oil"

"$2,800+ for service is a lot when you also need a new unit for $10-12,000 plus another $2,000 to run the lines inside the house. I also know we are being charged considerably more than other UGI customers, which I believe is based on a perceived ability to pay. I'm actually investigating this further with the PUC."

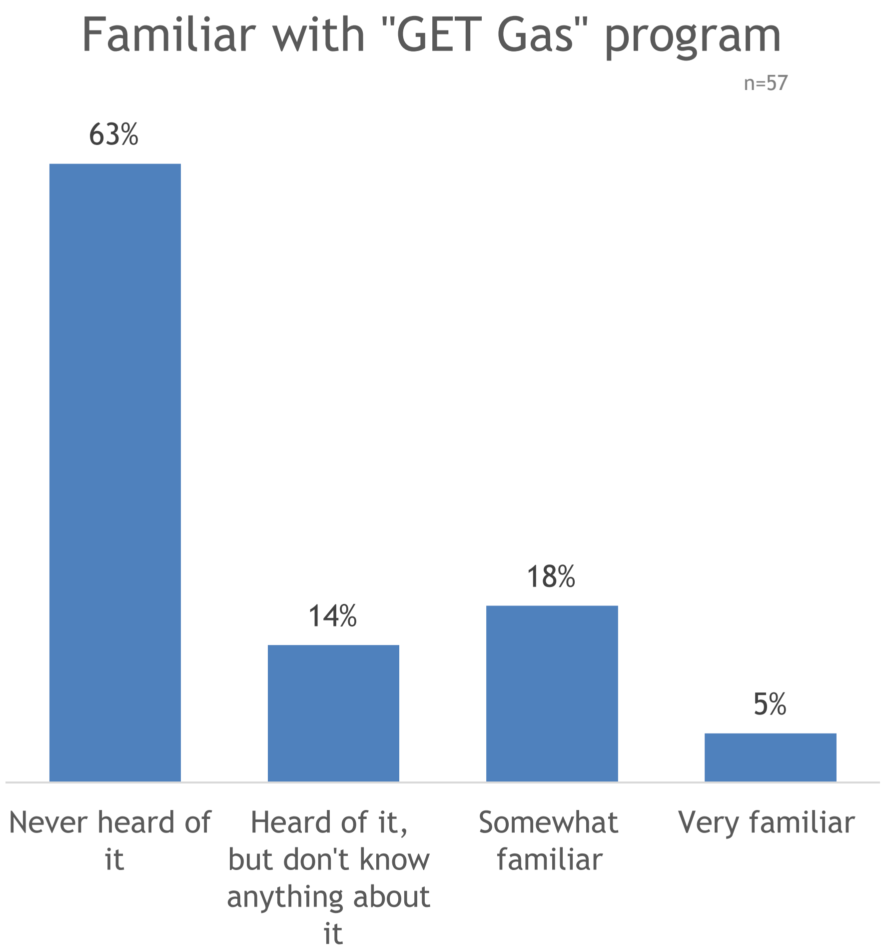
"Since I never got a response to the mess they left between the sidewalk and the curb I decided that it that is all they cared about the individual I was not going to pursue the matter."

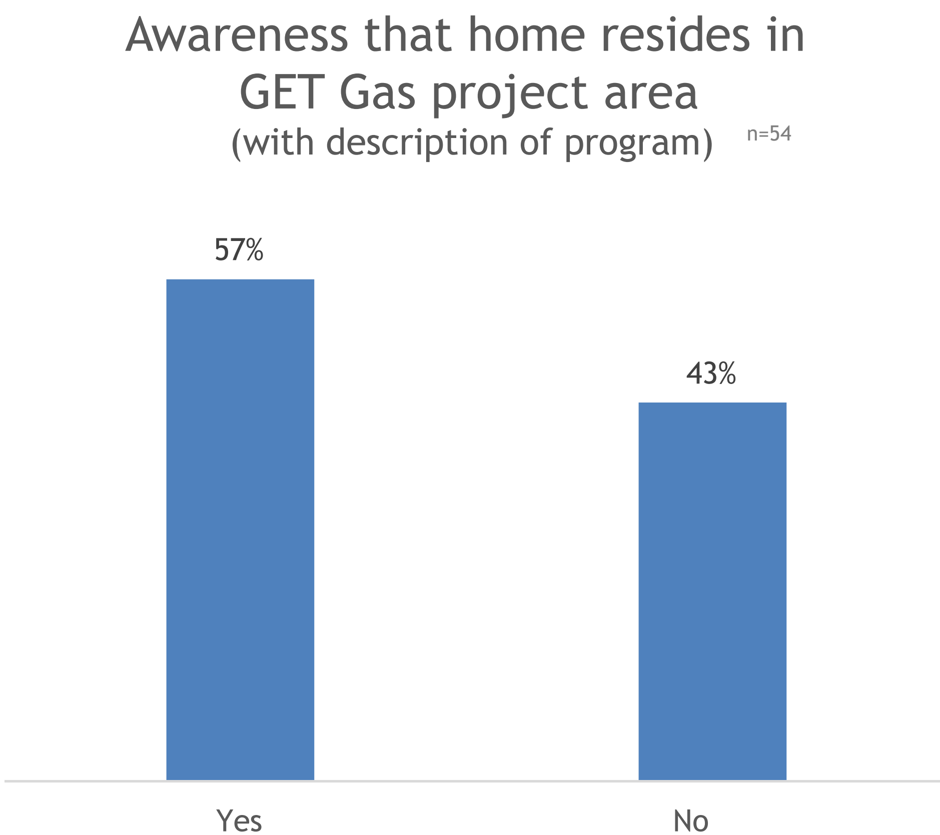
"UGI wants me to pay over three thousand dollars just to run the gas hookup to my house. This is a ridiculous price since they would be making money off of me indefinitely. Totally turned me off to going through with converting"

Familiarity GET Gas

Energy to do more®

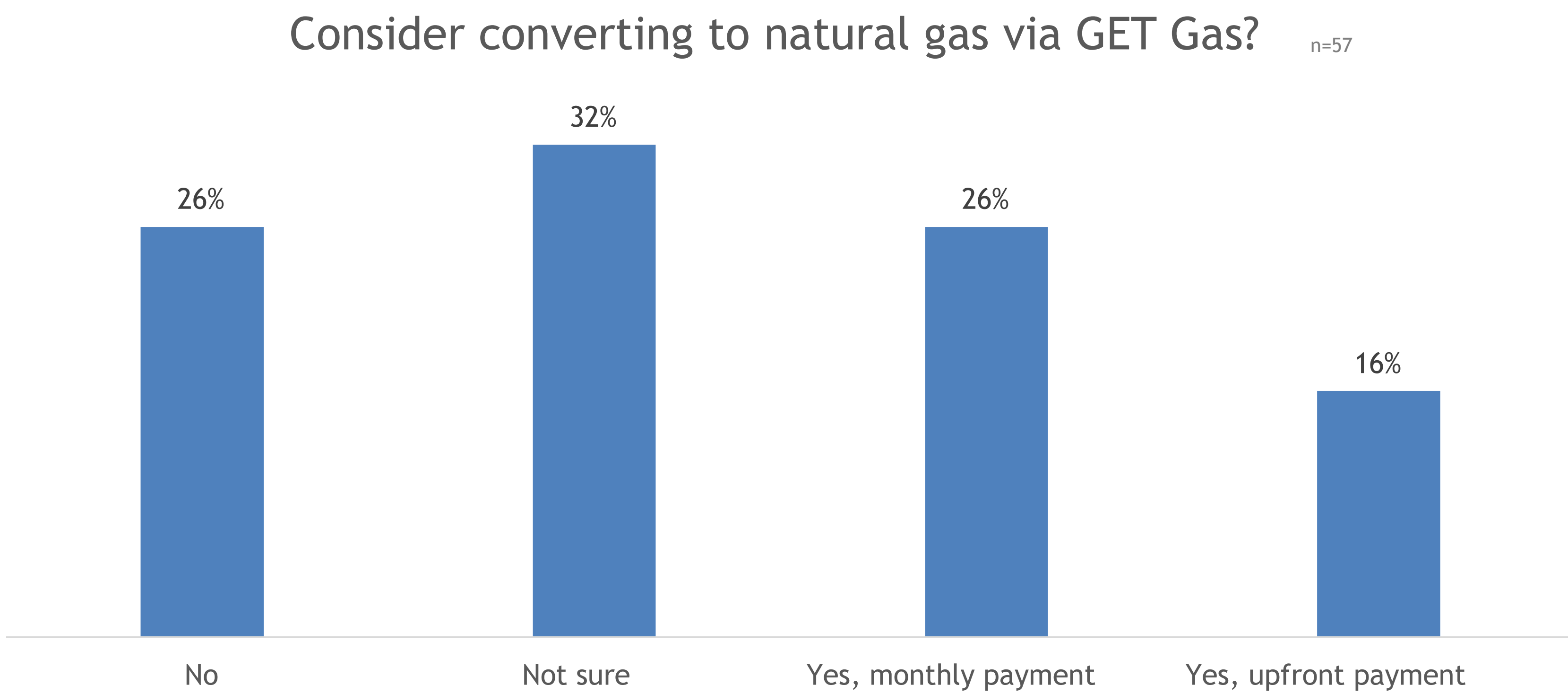
- Even though most homeowners are not familiar with "GET Gas" program name, they are aware of what the program offers





Interest GET Gas

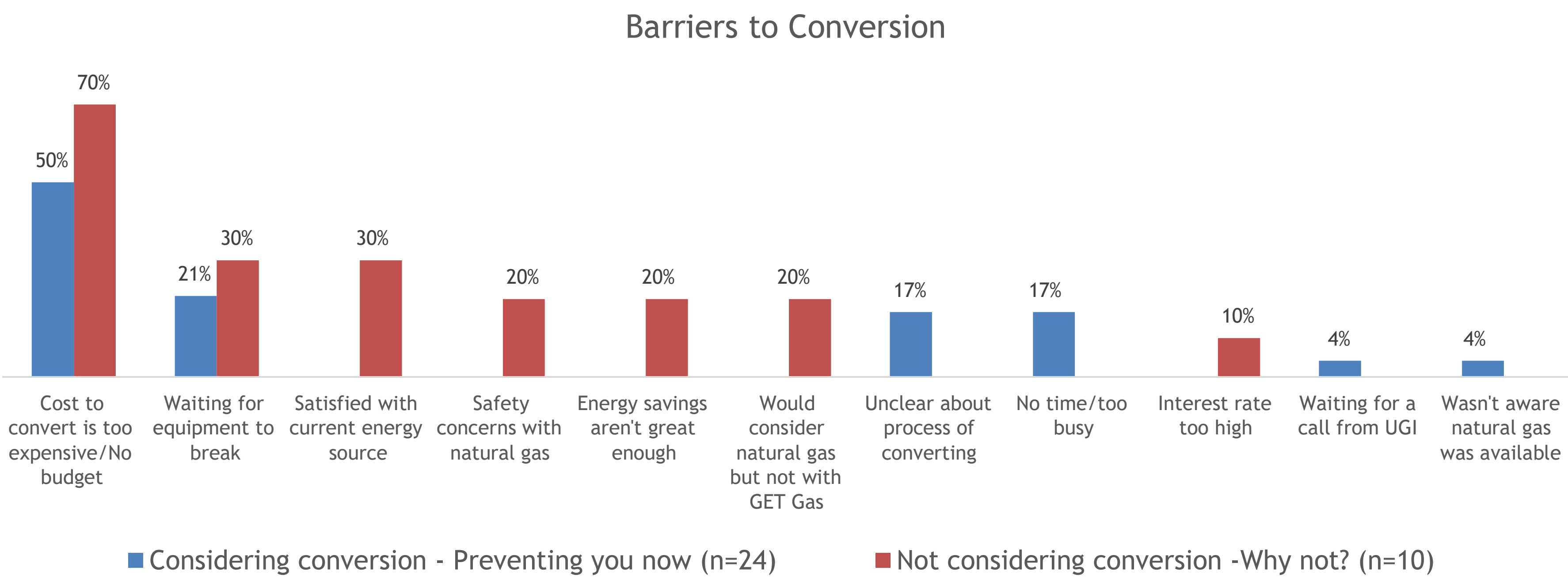
- One in four said they will not consider converting to natural gas via GET Gas while 32% are unsure
- One in four said they are interested in converting to natural gas via the GET Gas program using the monthly payment option with an additional 16% interested in the upfront payment option



Barriers GET Gas

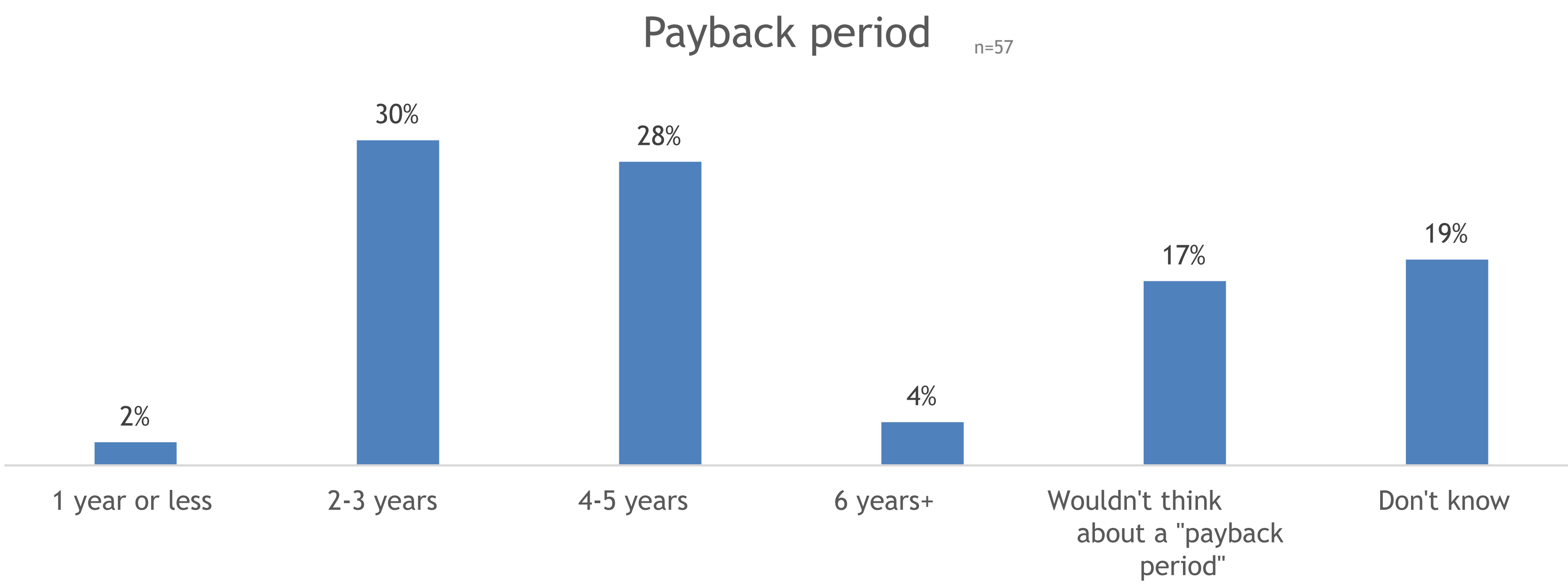
Energy to do more®

- Cost to convert is a significant barrier for GET Gas



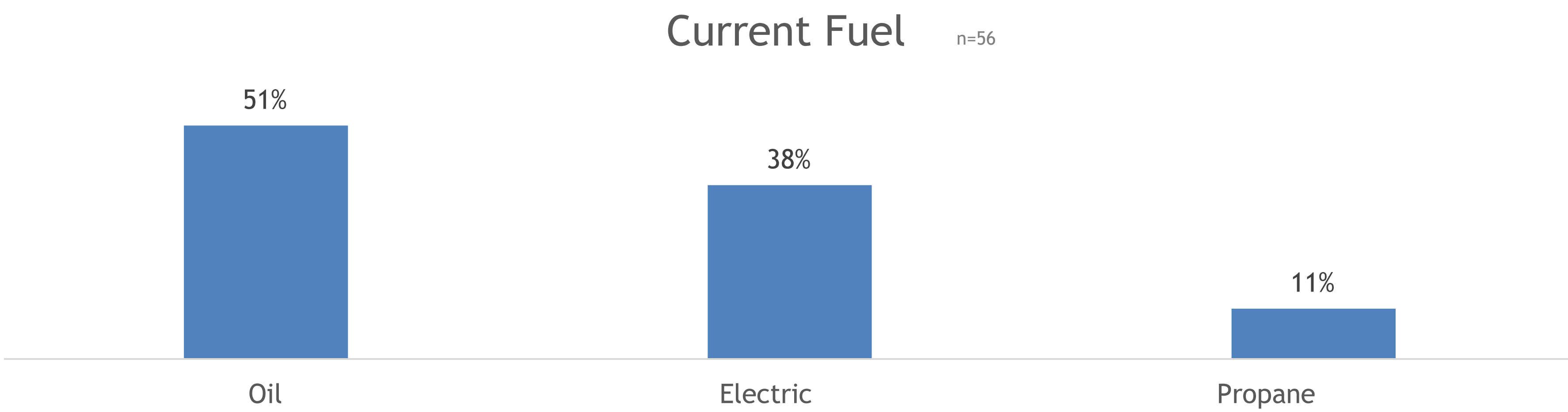
Payback Period

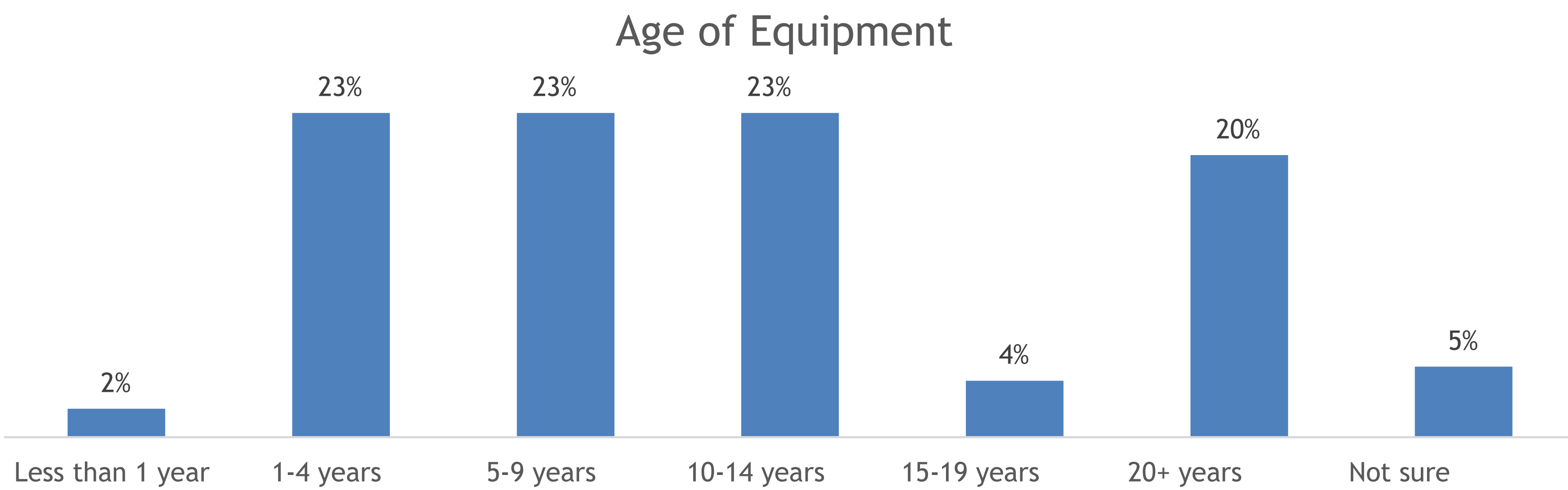
- Homeowners said a payback period of 2-5 years is optimal
- 17% said they don't think about conversion in terms of "payback period"



Existing Equipment & Fuel

Energy to do more®





UGI GAS EXHIBIT SMH-5

1		South Current Program Status	North Current Program Status	Central Current Program Status	Combined Proposal	Combined Proposal w/EEF	Formula
2	GET Investment Total	$ 39,956,856	$ 24,478,110	$ 8,631,009	$ 73,065,974	$ 73,065,974	
3	Total Projected Customers	5,343	3,134	1,196	9,673	9,673	
4	Total Cost Per Customer	$ 7,478	$ 7,811	$ 7,217	$ 7,554	$ 7,554	(2)/(5)
5	Number of Customers	5,343	3,134	1,196	9,673	9,673	
6	Residential Customers	5,335	2,994	1,188	9,517	9,517	
7	Commercial Customers	8	140	8	156	156	
8	Residential Use per Customer (Mcf)	85.7	103.4	109.3	94.2	94.2	
9	Commercial Use per Customer (Mcf)	327.0	417.0	471.0	415.2	415.2	
10	Residential Base Revenues per Customer	$ 551.41	$ 618.21	$ 640.48	$ 585.74	$ 585.74	
11	Commercial Base Revenues per Customer	$ 1,547.10	$ 1,850.71	$ 2,032.87	$ 1,835.72	$ 1,835.72	
12	Base Rate Revenues Residential	$ 2,941,772	$ 1,850,921	$ 760,890	$ 5,574,498	$ 5,574,498	(6)*(10)
13	Base Rate Revenues Commercial	$ 12,377	$ 259,099	$ 16,263	$ 286,372	$ 286,372	(7)*(11)
14	Residential Gross Up for CAP and Uncollectibles				$ 3,676	$ 3,676	(35)*(6)
15	Commercial Gross Up for Uncollectibles				$ 59	$ 59	(36)*(7)
16	Supported Investment Residential	$ 24,896,372	$ 15,664,438	$ 6,439,454	$ 47,177,269	$ 47,177,269	12/(29+31)
17	Supported Investment Commercial	$ 104,746	$ 2,192,772	$ 137,634	$ 2,423,584	$ 2,423,584	13/(29+31)
18	Supported Investment Residential w/ EEF Funds					$ 53,717,269	12/(29+31)+(33)
19	Supported Investment Commercial w/EEF Funds					$ 3,036,584	12/(29+31)+(34)
20	GET Investment Recovery Needed - Residential	$ 14,893,079	$ 5,807,888	$ 2,010,940	$ 22,322,250	$ 15,782,250	(2*22)-(18)+(14)
21	GET Investment Recovery Needed - Commercial	$ 62,659	$ 813,012	$ 42,981	$ 1,146,606	$ 533,606	(2*22)-(19)+(21)+(15)
22	Residential Base Revenue Share	99.6%	87.7%	97.9%	95.1%	95.1%	12/(12+13)
23	Commercial Base Revenue Share	0.4%	12.3%	2.1%	4.9%	4.9%	1-(22)
24	**Residential GET Customer Charge**	**$ 36.61**	**$ 25.44**	**$ 22.20**	**$ 30.76**	**$ 21.75**	(PMT((27)/12,120,(20)/(6)
25	Annual Commercial GET Charge Needed	$ 1,227	$ 802	$ 828	$ 1,100	$ 538	(PMT((27)/12,120,(21)/(7))*12
26	**Commercial Customer Charge**	**$ 7.86**	**$ 23.01**	**$ 13.08**	**$ 21.72**	**$ 7.86**	
27	**Commercial Volumetric Charge ($/Mcf)**	**$ 3.46**	**$ 1.26**	**$ 1.42**	**$ 2.02**	**$ 1.07**	((25)-(26)*12)/(9)
28	Afer-Tax WACC	6.98%					
29	Pre-Tax WACC	9.82%					(28)/(1-(30)
30	Tax Rate	28.8921%					
31	Depreciation Rate	2.000%					
32	Recovery Months	120					
33	EEF Funding for Residential	$ 6,540,000					
34	EEF Funding for Commercial	$ 613,000					
35	Avg Residential Gross Up for CAP and Uncollectibles	$0.70					
36	Avg Commercial Gross Up for Uncollectibles	$0.38					

UGI GAS EXHIBIT SMH-6

Meters Requiring Daily Metering

Rate Schedule	DS	IS	LFD	XD		
Count	1,236	141	25	37	1,439	*total units*
% of Total	86%	10%	2%	3%		

Initial Daily Metering Costs (per unit)

Materials	Labor	Transp./Licenses	Overhead		
$ 1,432	$ 186	$ 74	$ 189	$ 1,882	*total per unit*

Annual/Recurring Daily Metering Costs (per unit)

Materials	Labor	Transp./Licenses	Overhead		
$ 231	$ 131	$ 29	$ 44	$ 433	*total per unit*

Overall Impact

$ 2,707,943	**$ 623,550**
(Initial)	*(Annual/Recurring)*

UGI GAS STATEMENT NO. 10 – DANIEL V. ADAMO

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3006814

UGI Utilities, Inc. – Gas Division

Statement No. 10

Direct Testimony of
Daniel V. Adamo

Topics Addressed:	**Quality of Service Performance** **Credit Card & ACH Fee Waiver** **Universal Service and Energy Conservation Plan**

Dated: January 28, 2019

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Daniel V. Adamo. My current business address is 225 Morgantown Road, Reading, Pennsylvania 19611.

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

A. I am employed by UGI Utilities, Inc. ("UGI"), as Director – Customer Service. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has both a Gas Division ("UGI Gas" or "the Company"), which is a certificated natural gas distribution company ("NGDC"), and an Electric Division ("UGI Electric"), a certificated electric distribution company ("EDC"). On October 1, 2018 UGI Gas merged with its wholly-owned subsidiaries UGI Central Penn Gas, Inc. ("UGI CPG") and UGI Penn Natural Gas, Inc. ("UGI PNG"). UGI Gas is now administered through three geographical rate districts that correspond to the former service territories of UGI Gas (UGI South Rate District), UGI PNG (UGI North Rate District) and UGI CPG (UGI Central Rate District). In this position, I am responsible for managing the customer information center for UGI, as well as the customer accounting, credit and collections, customer outreach, and compliance departments. In this role I oversee regulatory compliance with Chapter 14 of the Public Utility Code, 66 Pa.C.S. §§ 1401, *et seq.*, related consumer regulations and compliance with generally applicable consumer protection, collection, consumer bankruptcy regulations, and the administration of all universal service programs.

Q. What is your educational and professional background?

A. I graduated from Lehigh University in 1998 with a B.S. in Mechanical Engineering. I started my employment with UGI in 1998. My full resume is attached as UGI Gas Exhibit DVA-1.

Q. Have you been involved in other proceedings before the Pennsylvania Public Utility Commission ("Commission")?

A. Yes. I testified on behalf of the Company's purchased gas cost filings in 2008 and 2009 as well as the Company's petition for approval of the Growth Extension Tariff ("GET Gas") Program in 2013. Please see UGI Gas DVA-1 for a complete listing of the proceedings in which I have testified and their docket numbers.

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

A. I am submitting this direct testimony on behalf of UGI Gas.

Q. What is the purpose of your testimony?

A. My testimony will discuss: (1) the Company's quality of service performance; (2) the Company's proposal for credit card and ACH fee waiver associated cost recovery; (3) the Company's Universal Service and Energy Conservation Plan ("USECP") for its gas customers; and (4) the Company's proposed combined Universal Service Plan Rider ("USP Rider") for its low income gas customers.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following UGI Gas Exhibits: DVA-1 through DVA-3. I am also sponsoring certain responses to the Commission's standard filing requirements as indicated on the master list accompanying this filing.

II. QUALITY OF SERVICE PERFORMANCE

Q. How does the Company evaluate its customer service performance?

A. The Company evaluates its customer service performance in several ways. One way is through the collection of data on performance goals set by the Commission's Bureau of Consumer Services ("BCS"), which are reported annually to the Commission and published in a comprehensive and publicly-available Customer Service Performance Report.[1] Based on these metrics, over the past three years the Company's quality of customer service has generally met or exceeded the Commission's benchmarks. Based on our information to date, most 2018 metrics will closely track those benchmarks. Considering the fact that the Company implemented a new billing and Customer Information System ("CIS") in September 2017, and the known challenges associated with CIS implementation, I consider our customer service performance results excellent.

Q. Are there any surveys by which the Company measures its customer service performance?

A. Yes. The Company participates in the JD Power Gas Utility Residential Customer Satisfaction Study.

[1] *See*, *2017 Customer Service Performance Report for Pennsylvania Electric & Natural Gas Distribution Companies*, published by the Pennsylvania Public Utility Commission, Bureau of Consumer Service at http://www.puc.state.pa.us/General/publications_reports/pdf/Customer_Service_Perform_Rpt2017.pdf

Q. Please explain the JD Power Gas Utility Residential Customer Satisfaction Study.

A. JD Power is a global market research company. 2018 marks the seventeenth year of its Gas Utility Residential Customer Satisfaction Study, an online survey that measures residential customer satisfaction with gas utility brands across the following six factors, in order of importance: billing and payment; price; corporate citizenship; communications; customer service; and field service. Satisfaction is calculated on a 1,000-point scale.

Q. How does JD Power evaluate customer satisfaction with gas utility brands?

A. JD Power contracts with several consumer survey panels to complete the survey, with online interviews conducted for 84 gas utilities across four quarterly fielding periods for four US regions (East, Midwest, South and West), each consisting of large and mid-sized utility categories. UGI Gas is in the "Large East" region for the study. This region consists of 12 gas utilities with more than 400,000 households.

Q. How is the Company judged in comparison to similarly-situated gas utilities?

A. UGI Gas was the highest ranked in their region in 2013 and 2014 and was named the JD Power Award winner for these years. UGI Gas came in second place in 2015, 2016, 2017, and 2018. In 2018, UGI Gas ended the field surveys within 3 points from first place. This is a significant accomplishment, particularly for a company that has implemented a new CIS. UGI Gas Exhibit DVA-2 consists of charts that depict the 2013-2018 customer satisfaction rankings for the eleven natural gas utilities that make up the Large East region.

Q. Are there any other ways that UGI Gas evaluates its customer service performance?

A. Yes. UGI Gas is required to report to the Commission the results of telephone transaction surveys of residential and small business customers that have recently contacted the Company. The purpose of these surveys is to assess the customer's perception of the interaction with UGI Gas and fulfill reporting requirements for quality of service benchmarks and standards pursuant to Commission regulations. All EDCs and major NGDCs utilize a common survey which was developed collaboratively with the Commission. Metrix Matrix, a research firm used by all EDCs and major NGDCs for this purpose, contacts individual consumers until it meets a monthly quota of completed surveys for each company. Each year Metrix Matrix completes approximately 700 surveys for each participating utility, including UGI Gas. A benchmark, based on a scale of 1-10, is then developed for all northeastern natural gas utilities based on approximately 5,500 total surveys. Table 1 below sets out the UGI Gas survey results from 2016 through 2018.

Table 1. Customer Satisfaction Survey Results

Calendar Year	Overall Satisfaction	Benchmark	Call Rep Satisfaction	Benchmark	Field Rep Satisfaction	Benchmark
2016	9.10	9.11	9.54	9.25	9.55	9.49
2017	9.08	9.18	9.52	9.31	9.56	9.60
2018	8.96	9.10	9.41	9.22	9.31	9.51

The above results show that UGI Gas closely tracks the customer service benchmark for our industry group and, in the case of call representative satisfaction, exceeds that benchmark. These customer satisfaction survey results demonstrate strong performance on the part of our call center and field staff, which is consistent with our high marks from JD Power. Although there is certainly opportunity to improve overall customer satisfaction, considering the CIS redevelopment in September of 2017, the fact that the Company has maintained a strong showing in the Metrix Matrix survey is particularly impressive. While the Company continually strives to improve the customer experience with its call representatives and field representatives, considering the Company's already strong performance in these areas, the Company is exploring other ways to improve overall customer satisfaction, including the expansion of payment options proposed in this proceeding.

III. CREDIT CARD AND ACH FEE WAIVER

Q. What is the Company's proposal regarding credit card and ACH payments?

A. The Company is planning on offering a fee free credit card payment option and expanding its ACH payment options to ensure that all online and telephonic ACH and credit card payments are free of fees.

Q. What forms of online and telephonic payments are currently accepted by UGI?

A. UGI Customers may pay via the options outlined in Table 2 below:

Table 2. Currently Accepted Form and Means of Payment

Payment Vehicle	Possible Form of Payment
UGI Website/Customer Portal	ACH, Credit Card
Third-party vendor website	ACH, Credit Card
UGI Telephone	ACH, Credit Card
Third-party vendor telephone	ACH, Credit Card

Q. Who pays for the cost of processing these forms of telephonic and online payments for customers?

A. The cost of processing ACH transactions on the Company's portal and via telephone are embedded in the Company's distribution rates. However, where ACH and credit card payments are made by the Company's third-party vendor, those costs result in a per-transaction charge that is passed on directly to the customer.

Q. Does the Company know how many customers avail themselves of telephonic and internet-based ACH and credit card payment methods?

A. Yes. In the historic test year ended September 30, 2018 ("HTY"), UGI Gas received 312,963 payment transactions from customers via the third-party vendor's website and through telephone. In the HTY, customers paid a total of $1,236,204, at $3.95 per transaction, in third-party service charges for payments made by ACH and credit card payments. Table 3 details the type of payments by class.

Table 3. Percentage of Payments by Type in HTY

Payment Type	**Number of Payments**	**% of Payments**
Residential ACH	54,646	17.46%
Residential Credit Card	244,540	78.14%
Commercial ACH	3,393	1.08%
Commercial Credit Card	9,999	3.19%
Industrial ACH	72	0.02%
Industrial Credit Card	313	0.10%
Total	**312,963**	**100%**

Q. Why is it important that credit card and bank card payment options be available to UGI Gas's customers?

A. Through the Company's customer satisfaction surveys and outreach, the Company has observed a strong interest from customers for fee-free payment options. Most recently in the first wave of JD Power surveys for 2019, 2 out of 18 opened-ended comments on "what does the utility needs to do to improve" called out the offering of fee-free credit card transactions. Additionally, the Company has an online customer panel of approximately 1,000 customers who volunteered through an open solicitation to periodically participate in online customer surveys to provide the Company with feedback to help us identify areas of potential improvement to our customer service. In a recent survey, 670 panelists responded to the Company's question of what should be the Company's top customer satisfaction initiatives. Of the fourteen options to choose from, 21 percent of the panelists ranked fee-free credit card payments as their top priority and 35 percent placed it in their top three. Overall, this resulted in fee-free credit card payments being ranked as the number one priority for this customer panel.

Q. Do you have any insights on payment trends and customer expectations?

A. Yes. Other utilities in recent rate proceedings have been successful in incorporating these fees into their base rates.[2] The Company agrees with this approach because it should increase the adoption of credit cards and ACH as payment options. In connection with the Company's proposed treatment of credit card and ACH fees, the Company has projected a 30 percent increase in customer use of the credit card option in the first year after the fees are incorporated into base rates, based on actual results from other utilities. Accordingly, as shown on UGI Gas Exhibit DVA-3, the Company feels that a commensurate 30 percent increase in payments made from 312,963, in the HTY to 406,852 in the fully projected future test year ending September 30, 2020 ("FPFTY"), is a reasonable expectation. Applying this 30 percent adoption increase to the HTY transaction fees results in a total increase in costs of $1,607,065. However, factoring in projected cost savings from the increased adoption of ACH and credit card payments reduces the projected cost to $1,595,892. When adjusted for the percentage of costs

[2] *See, e.g., PaPUC v. Duquesne Light Co.*, Docket No. R-2018-3000124 (Opinion and Order entered December 20, 2018).

attributable to the Electric Division based on the Modified Wisconsin Formula percentage of 9.35, the cost increase for UGI Gas amounts to $1,446,676. Therefore, based on this projected increase, the Company has adjusted its operating expense upwards by $1,446,676 as referenced in the testimony of Stephen F. Anzaldo (UGI Gas St. No. 3). As customers no longer will pay these fees directly, this internalization of credit card fees will have a parallel decrease in the fees customers will pay directly.

Q. How does the Company propose to allocate these costs?

A. The Company proposes to allocate these costs in accordance with the applicable allocation factor in the cost of service study for expense category "Customer Accounts" sponsored by UGI Gas Witness Paul R. Herbert (UGI Gas St. No. 6).

Q. What accounts for the anticipated cost savings due to increased adoption of ACH and credit card payments?

A. These savings are due to the processing fees that the Company currently pays for check and internal ACH payment processing that will be supplanted by the customers' adoption of third-party ACH and credit card payments.

Q. Why does the Company believe that it is reasonable to provide fee-free ACH and credit card payments for customers?

A. The Company's primary purpose in providing fee-free ACH and credit card payments is to improve customer service and satisfy customer expectations in a rapidly developing economy where customers are able to purchase nearly everything other than utility service on a credit card. However, even the utility industry is evolving in this respect, as evidenced by the recent Duquesne Light rate case, in which the Commission approved a settlement including a proposal to waive credit card and ACH fees by a third-party vendor and recover those costs from all customers.[3] This proposal also will alleviate the burden placed on those customers, many of whom are low income, who utilize credit cards for utility bill payments and result in parity between different forms of payment options.

Q. Is there an additional reason why the cost of online and telephonic ACH and credit card fees should be recovered from all customers?

A. Yes. Currently, many of these transaction costs are already being recovered from all customers, including the cost of processing ACH transactions and the cost of processing check payments. In my view, the cost of processing third-party online and telephonic ACH and credit card transactions should be recovered in a similar and consistent fashion.

Q. Will low-income customers be disadvantaged by including these bill pay costs in base rates?

A. No, to the contrary, since low-income customers are either frequent users of these payment methods or would be if they were offered free of fees, such customers will benefit from the Company's proposal. The Company recently surveyed customers that were of a level 1 low-income status, which equates to income under 150 percent of the federal poverty guidelines, and asked if they currently use a credit card to pay their UGI

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[3] *PaPUC et al. v. Duquesne Light Company*, Docket No. R-2018-3000124, "Joint Petition for Approval of Settlement" (Order entered on December 20, 2018).

bill. Of the approximate 1,300 respondents, 400 use credit cards to pay their bill. We additionally asked if there were no fees, would the customer be more willing to pay their bill via credit card. Of the respondents, 550 out of the 889 who are not using a credit card to pay their bill said they would pay via credit card if there were no fees.

IV. OVERVIEW OF COMPANY'S USECP

Q. Please describe the current administration of UGI's USECP.

A. The UGI USECP is centrally managed for each of the Gas Division's three rate districts, as well as for the Electric Division.

Q. What is the state of the USECP currently?

A. The most recent USECP was filed on June 30, 2017, at Docket No. M-2017-2598190 for the period of January 1, 2018 through December 31, 2020. That USECP is still pending Commission approval as of the date of this filing. On November 1, 2018, as a result of the October 1, 2018 merger, a revised USECP was filed that recognized the three distinct rate districts within the Gas Division of UGI Utilities. The revised USECP maintained separate budgets for each rate district, due to each rate district maintaining separate distribution rates and costs expended within each rate district recovered from the ratepayers receiving distribution service within those districts.

Q. What programs does the pending USECP offer?

A. Both the Gas Division and the Electric Division offer the following programs: (1) the Customer Assistance Program ("CAP"); (2) the Low-Income Usage Reduction Program

("LIURP"); (3) Operation Share Energy Fund (hardship fund); and (4) the Customer Assistance and Referral Evaluation Services ("CARES") program.

Q. What changes do you anticipate as a result of this proceeding?

A. The Company does not propose any programmatic changes in this proceeding. However, as discussed in the next section of my testimony, as part of the Company's request to implement uniform distribution rates in this proceeding, it is proposing to merge the Universal Service Plan ("USP") Rider into one uniform cost recovery program. To this end, the Company would amend its USECP to permit one budget for each program, rather than maintaining separate budgets by rate district.

Q. Are there any benefits from having one program budget for UGI Gas rather than separate rate district budgets?

A. Yes. From time to time the Company has faced challenges in spending all of its program budgets for one or more of the rate districts. In years where those funds were not spent within the rate district, they were rolled over to the next budget cycle rather than being reallocated to a different rate district. By having one budget for all of UGI Gas, the Company will have more flexibility in utilizing funds where they are needed and reducing the amount of annual rollover of unspent budgeted program funds.

Q. Please explain how the Company proposes to recover the costs of its universal service programs.

A. UGI Gas is permitted to recover costs for each of its universal service programs under its USP Rider with an annual reconciliation for costs and recoveries. There is an offset for CAP credits and pre-program arrearages for customers receiving shortfall credits above the enrollment projected in each rate district's last base rate case. Currently UGI Gas's USP Rider is substantively identical for each of its rate districts. To the extent that any minor differences exist in language, the Company's proposed USP rider in this proceeding is the one currently in effect for the UGI South Rate District. Company witness David E. Lahoff (UGI Gas St. No. 8) describes in his testimony the budgeted universal service costs that have been accounted for in the USP rider surcharge, and the Company's offset to CAP credits and pre-program arrearage for customers receiving shortfall credits above the projected CAP enrollment.

Q. What is the basis for the offset above the projected CAP enrollment?

A. This offset reduces the Company's recovery of CAP spending above projected enrollment to account for write-offs of bad debt that would have arguably occurred if not for CAP.

Q. Do you have a projection for UGI Gas's CAP enrollment for the end of the FPFTY?

A. Yes. I project that UGI Gas's CAP enrollment at September 30, 2020 will be 21,530 as shown in Table 4 below:

Table 4. CAP Enrollment

Rate District	FY2018	FY2019	FY2020
North	6,427	7,070	7,423
South	9,863	10,849	11,392
Central	2,351	2,586	2,715
Total	**18,641**	**20,505**	**21,530**

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS EXHIBIT DVA-1

Daniel V. Adamo
Director – Customer Service

Work Experience

UGI Utilities, Inc., Reading, PA

August 2018 – Present	Director Customer Service
January – August 2018	Senior Manager Billing & Compliance
2016 – 2018	Functional Lead – UNITE Project
2015 – 2016	Manager Operations
2013 – 2015	Director Marketing (Programs and Strategy)
2011 – 2013	Business Development Director
2009 – 2011	Regional Marketing Manager
2007 - 2009	Manager Rates
2005 - 2007	Project Engineer Gas Supply
2004 – 2005	Project Engineer Key Accounts
2001 – 2004	Staff Engineer New Business
2000 – 2001	Customer Service Supervisor
1998-2000	Engineer 1

Previous Testimony

2008 UGI Penn Natural Gas Purchased Gas Cost Filing: Docket No. R-2008-2039284

2009 UGI Penn Natural Gas Purchased Gas Cost Filing: Docket No. R-2009-2105904

2009 UGI Central Penn Gas Purchased Gas Cost Filing: Docket No. R-2009-2105909

2009 UGI Utilities – Gas Division Purchased Gas Cost Filing: Docket No. R-2009-2105911

2013 Growth Extension Tariff Pilot Programs Filing: Docket No. P-2013-2356232

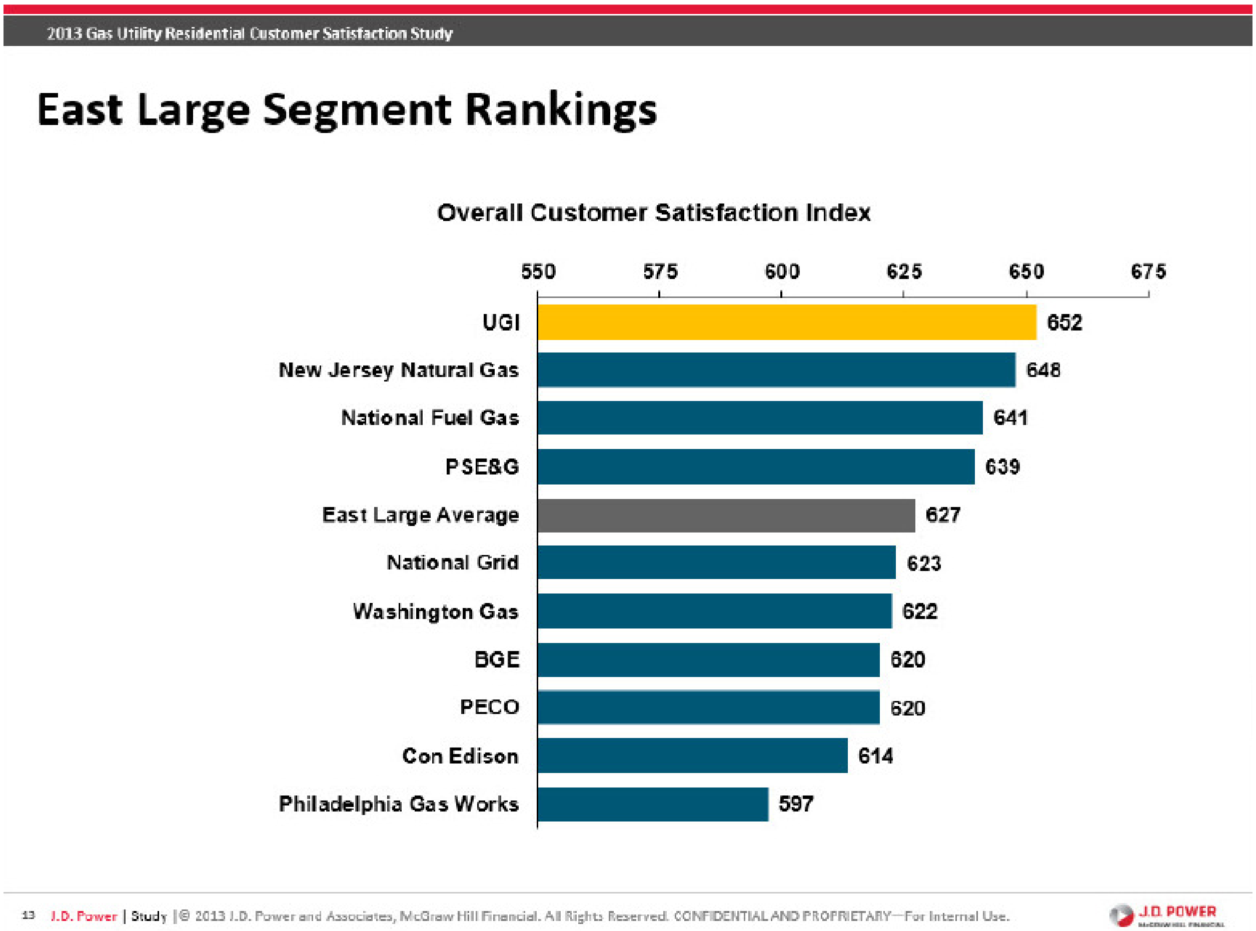
Education

B.S. in Mechanical Engineering from Lehigh University, 1998

UGI GAS EXHIBIT DVA-2

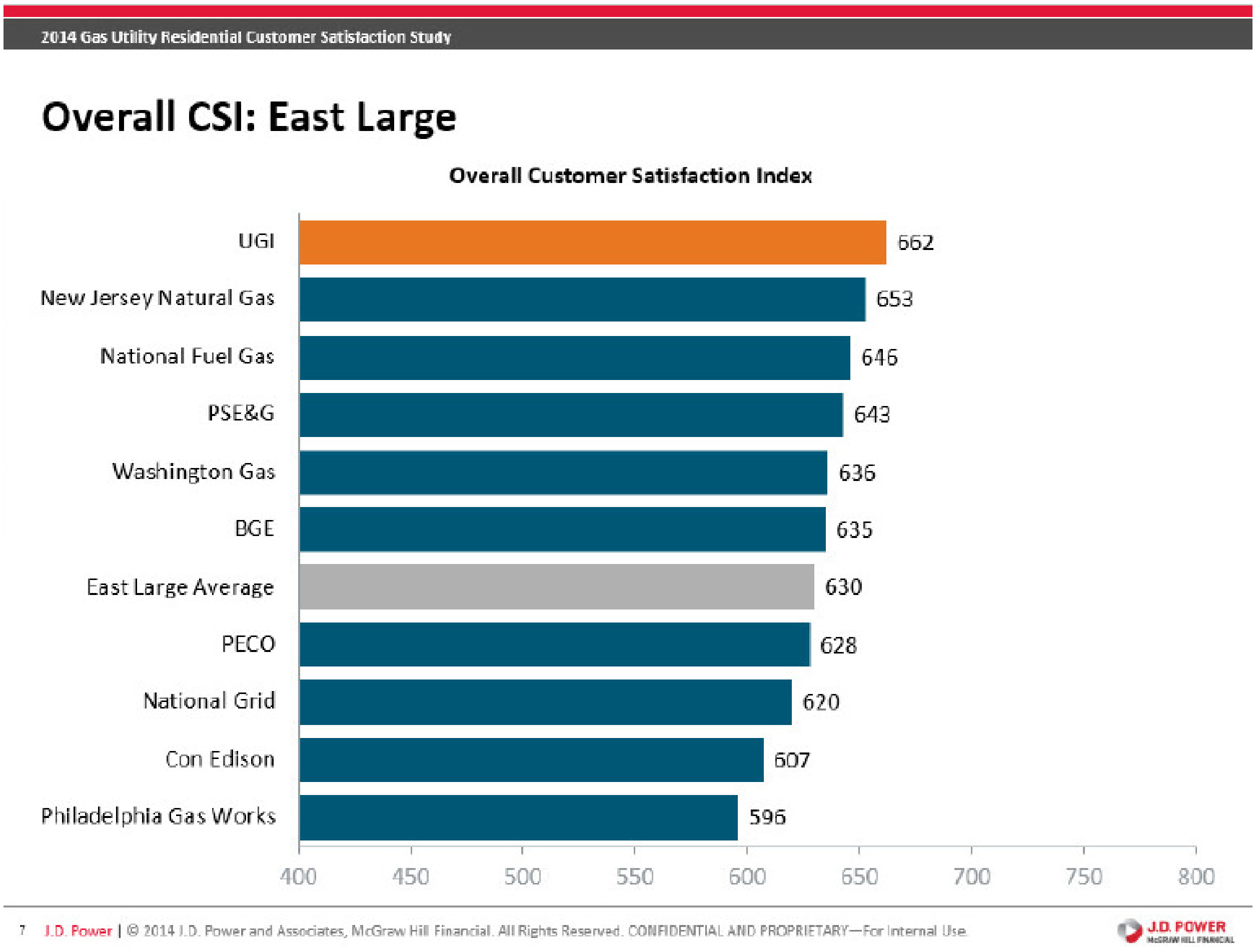
JD Power Gas Utility Residential Customer Satisfaction Study Results 2013-2018

2013



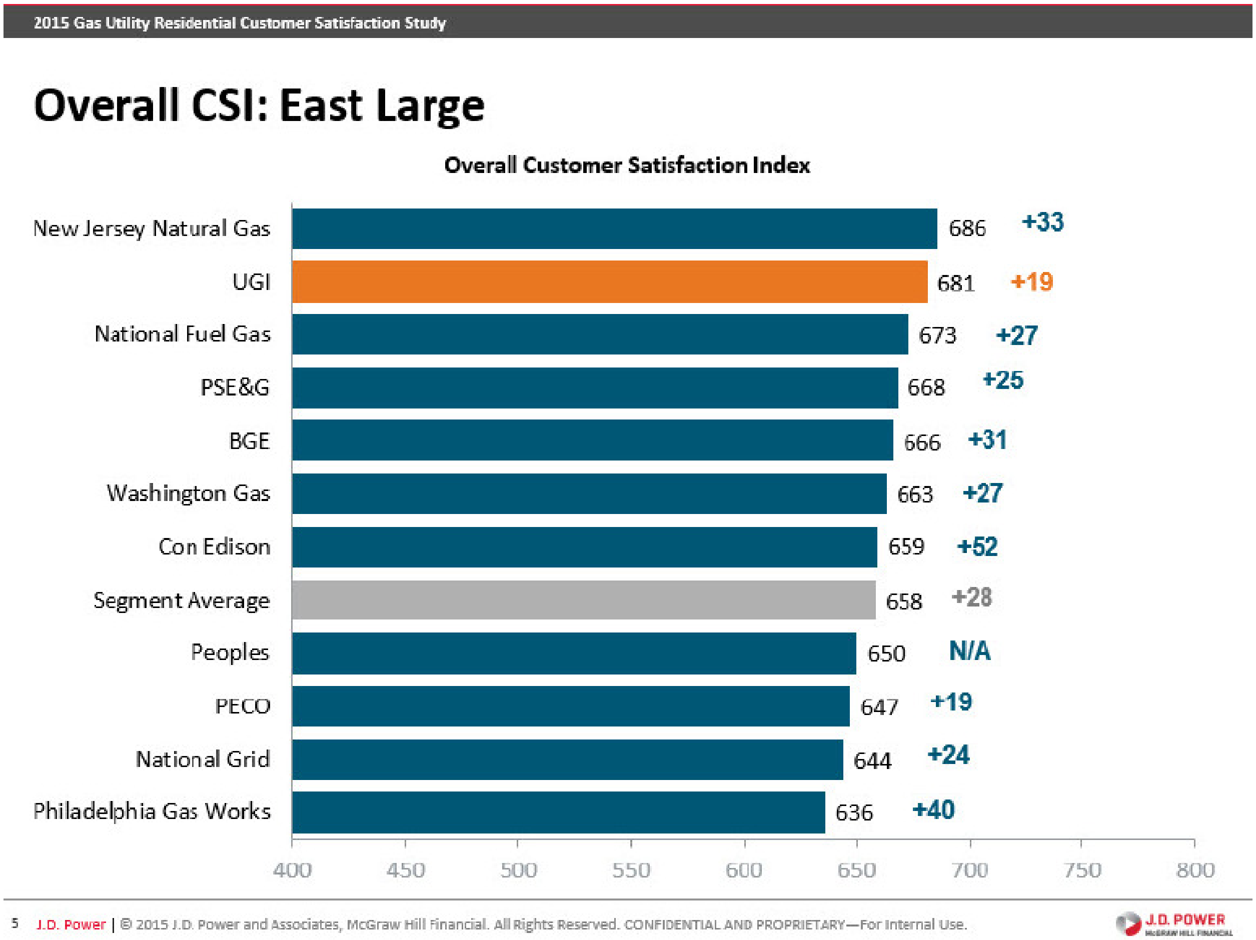
**JD Power Gas Utility Residential Customer Satisfaction Study Results
2013-2018**

2014



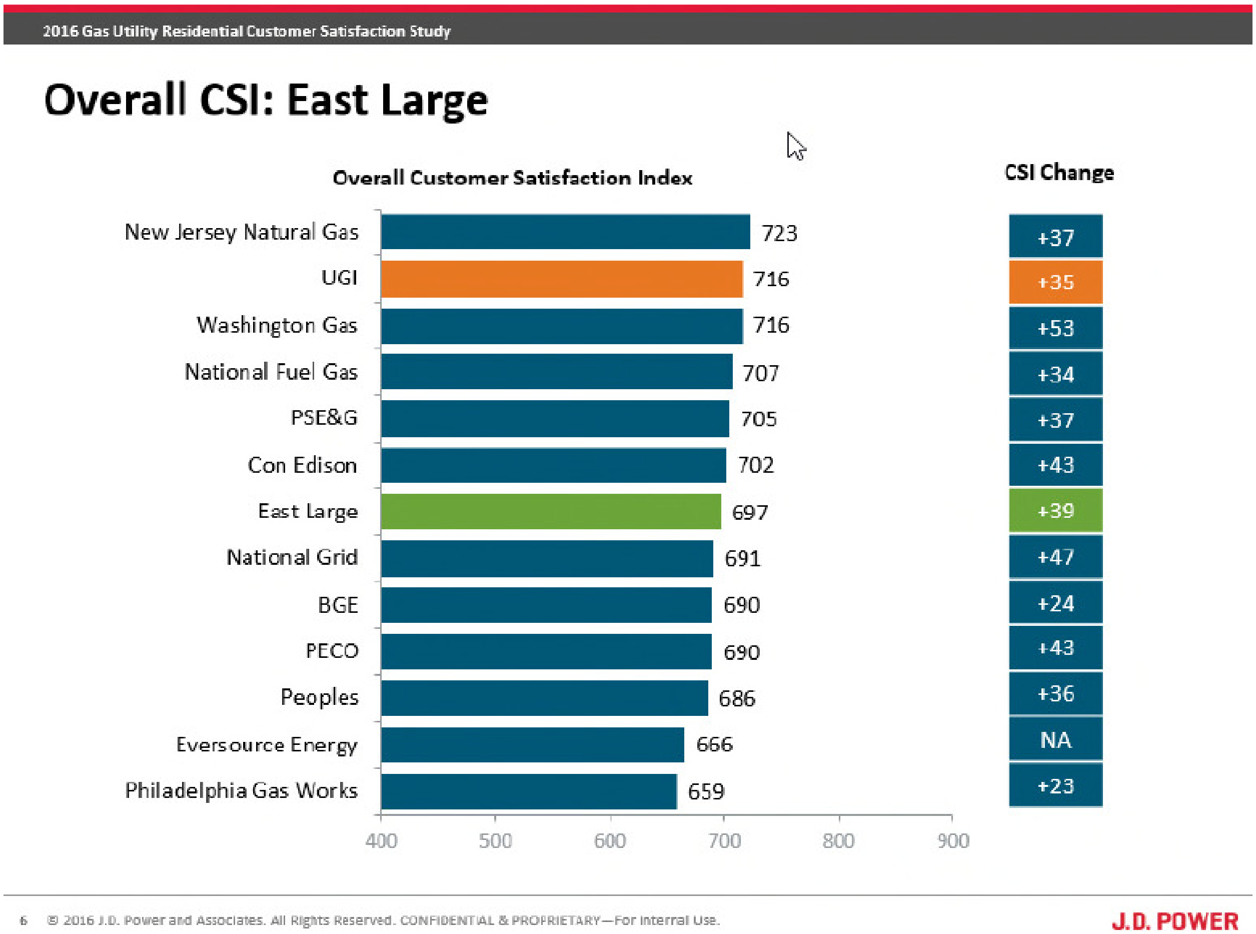
**JD Power Gas Utility Residential Customer Satisfaction Study Results
2013-2018**

2015



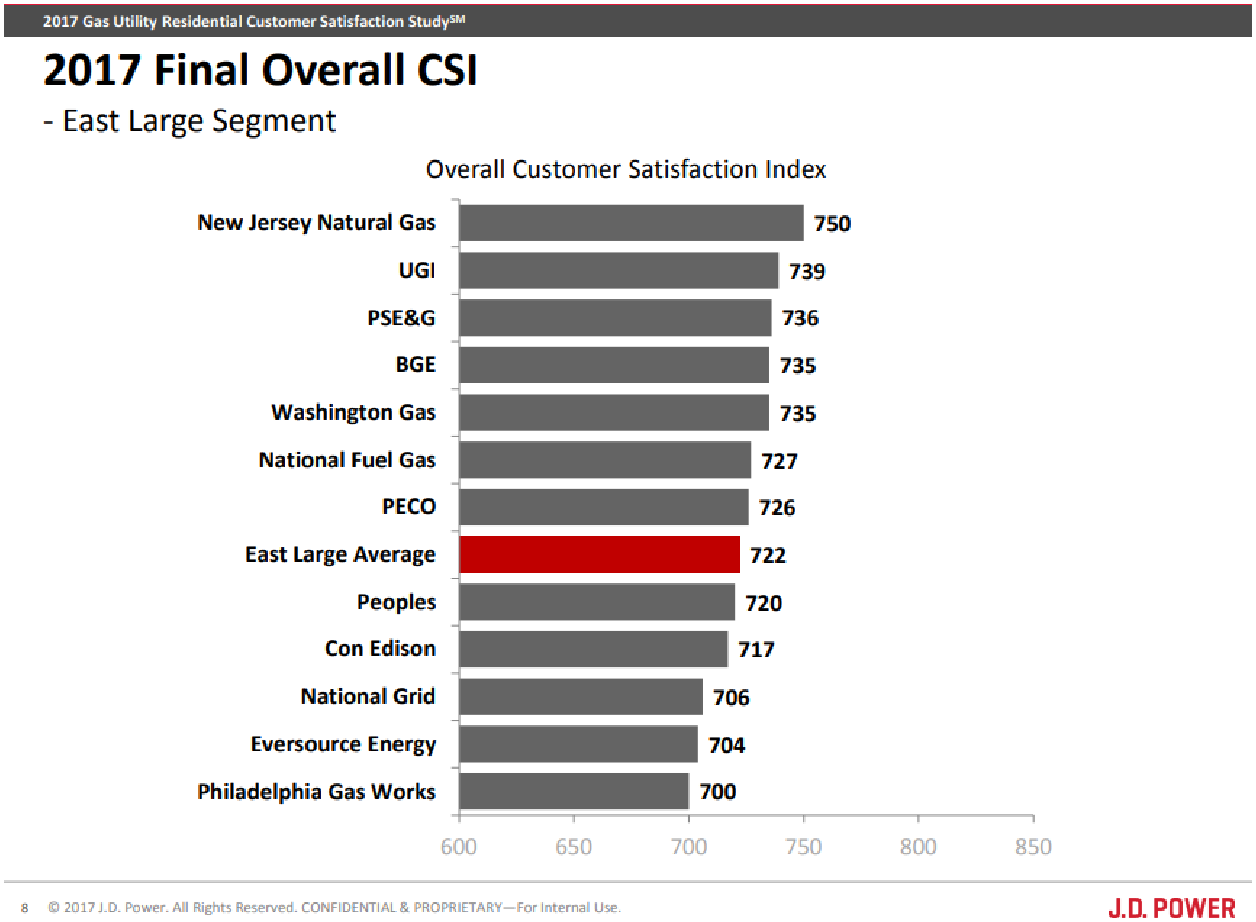
JD Power Gas Utility Residential Customer Satisfaction Study Results
2013-2018

2016



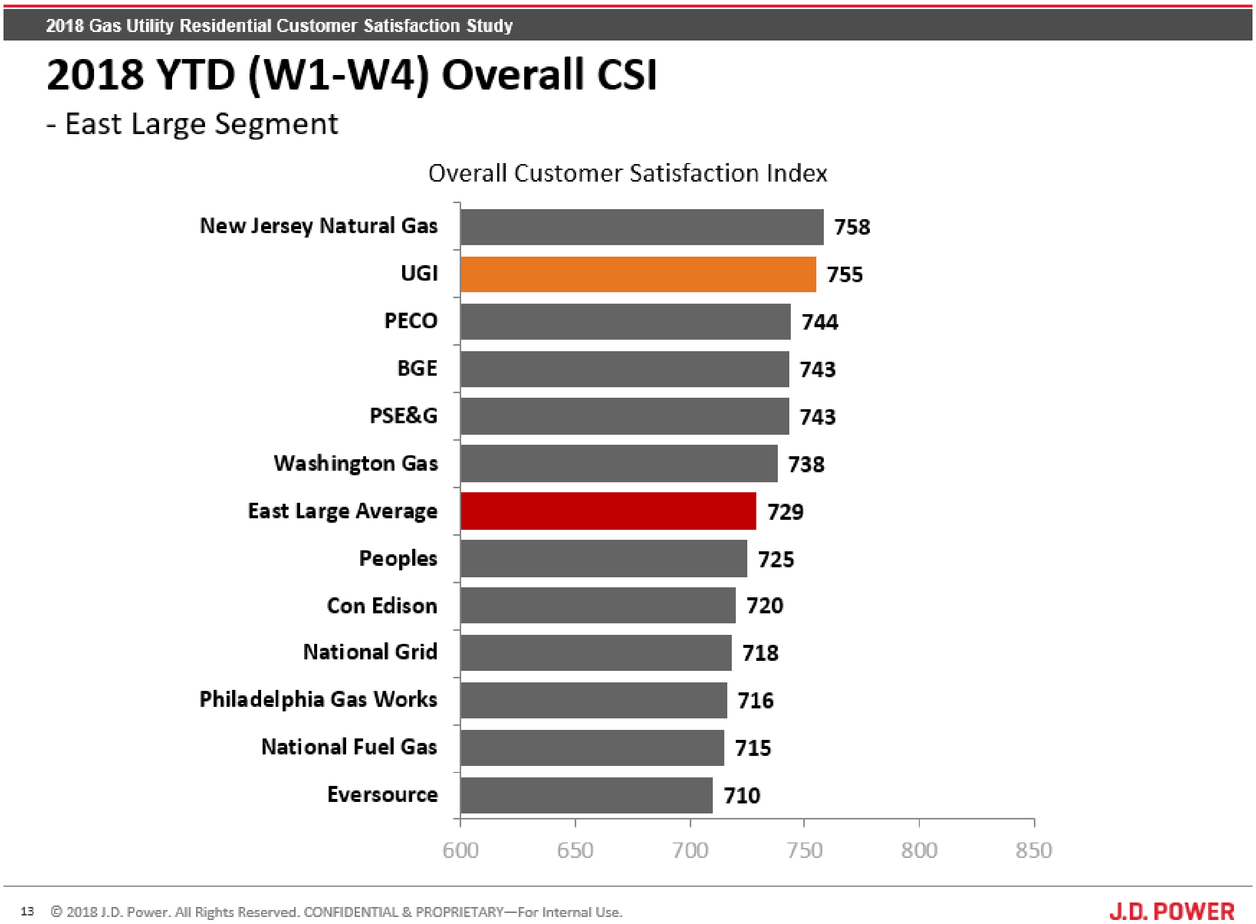
**JD Power Gas Utility Residential Customer Satisfaction Study Results
2013-2018**

2017



**JD Power Gas Utility Residential Customer Satisfaction Study Results
2013-2018**

2018



UGI GAS EXHIBIT DVA-3

Fee-Free Credit Card and ACH Payment Proposal

	Historic Test Year 2018 Data			
HTY Transactions	312,963	100%	$1,236,203.85	
Plus 30% increased adoption			$1,607,065.01	

	Cost Savings			
	% of Historic Test Year Transactions	# of Transactions	Rate	Credit to Increased Costs
ACH Processing	41%	38,494	$0.06	$2,309.67
Check Processing	59%	55,394	$0.16	$8,863.11
Total Cost Savings	100%	93,889		$11,172.78
Net UGI Cost Increase				$ 1,595,892.23
Less UGI Electric MWF 9.35%				149,215.92
Net UGI GAS Cost Increase				$ 1,446,676.30

UGI GAS STATEMENT NO. 11 – NICOLE M. MCKINNEY

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3006814

UGI Utilities, Inc. – Gas Division

Statement No. 11

Direct Testimony of
Nicole M. McKinney

Topics Addressed: **Taxes and Tax Adjustments**

Dated: January 28, 2019

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Nicole M. McKinney. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

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

A. I am employed by UGI Utilities, Inc. ("UGI") as Manager of Tax and Regulatory Accounting. UGI is a subsidiary of UGI Corporation ("UGI Corp."). UGI's Gas Division ("UGI Gas") and Electric Division ("UGI Electric") are regulated by the Pennsylvania Public Utility Commission ("Commission" or "PA PUC").

Q. What are your principal duties and responsibilities as Manager of Tax and Regulatory Accounting?

A. My primary duties as Manager of Tax and Regulatory Accounting include the preparation of tax data to be reported in UGI's various United States Securities and Exchange Commission and regulatory filings, as well as its various federal and state income and non-income tax return related filings. Additionally, I maintain the current and deferred income tax accrual and expense accounts, perform tax research, and assist UGI with tax matters as they arise. Additionally, I manage the reporting of the Company's various tax and accounting filings with the PUC and the Federal Energy Regulatory Commission, as well as maintain the accounting for our regulatory asset and liability accounts.

Q. Please describe your educational background and professional experience.

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

Q. Please describe the purpose of your testimony.

A. I am providing testimony on behalf of UGI Gas. I will explain the Company's *pro forma* tax adjustments to its principal accounting exhibits for the fully projected future test year ending September 30, 2020 ("FPFTY"). I will also explain the tax adjustments made to the results of UGI Gas's historic test year ended September 30, 2018 ("HTY") and future test year ending September 30, 2019 ("FTY").

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

A. Yes. Together with other Company witnesses, I am sponsoring portions of UGI Gas Exhibit A (Fully Projected), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic) that pertain to tax-related issues. These exhibits comprise UGI's principal accounting exhibits for the HTY, FTY, and FPFTY. I am also sponsoring certain responses to the Commission's standard filing requirements as indicated on the master list accompanying this filing.

II. TAX ADJUSTMENTS

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

A. As explained in the direct testimony of Mr. Stephen F. Anzaldo (UGI Gas Statement No. 3), UGI's principal accounting exhibit is UGI Gas Exhibit A (Fully Projected), which includes a presentation for the FPFTY ending September 30, 2020. Section D of UGI Gas Exhibit A (Fully Projected) presents necessary adjustments to budgeted levels of expense items and revenues. The *pro forma* adjustments related to taxes are summarized in Schedules D-31 through D-34. These tax adjustments are used to derive UGI Gas's *pro forma* income at present and proposed rates as set forth in Schedule A-1 of the same exhibit.

UGI Gas Exhibit A (Historic) and UGI Gas Exhibit A (Future) follow the format of UGI Gas Exhibit A (Fully Projected), but reflect data for the HTY ended September 30, 2018, and the FTY ending September 30, 2019. This information is provided in an effort to comply with the Commission's filing requirements and provides a basis for comparing UGI's FPFTY claims with actual book results from the HTY and adjusted FTY results. Section D to UGI Gas Exhibit A (Historic), Schedule D-31, and UGI Gas Exhibit A (Future), Schedule D-31 include adjustments that share the same methodology as used in Schedule D-31 of UGI Gas Exhibit A (Fully Projected).

A. TAXES OTHER THAN INCOME TAXES

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

A. TOTI amounts were based on the plan year budget, as adjusted for reasonably known and measurable changes to various payroll taxes as supported by the direct testimony of Mr. Stephen F. Anzaldo (UGI Gas Statement No. 3). These adjustments are shown on UGI Gas Exhibit A (Fully Projected), Schedule D-31. The net adjustment of $156,000 is brought forward to Schedule D-3, page 2.

B. TAX CUTS AND JOBS ACT

Q. What is the Tax Cuts and Jobs Act of 2017?

A. The Tax Cuts and Jobs Act of 2017 ("TCJA") was tax reform legislation signed into law on December 22, 2017. Most pertinent for this proceeding, the TCJA:

- Reduced the corporate federal income tax rate from 35 percent to 21 percent, effective January 1, 2018; and
- Modified tax depreciation rules.

Q. How has the Commission approached the implementation of the TCJA in rates for the fiscal year ended September 30, 2018?

A. The Commission undertook certain statewide actions regarding the TCJA in 2018. By Secretarial Letter dated February 12, 2018, at Docket No. M-2018-2641242, the Commission directed major jurisdictional utilities, including UGI, to file certain data concerning the effects of the TCJA. The jurisdictional public utilities that did not have pending rate cases before the Commission at that time submitted comments and data in response to the February 12, 2018 Secretarial Letter on or before March 9, 2018. UGI was one of the Companies that submitted comments. Thereafter, the Commission issued an Order dated March 15, 2018, that established temporary rates for all public utilities not currently involved in a pending Section 1308(d) general rate increase proceeding. *See Tax Cuts and Jobs Act of 2017*, Docket No. M-2018-2641242, p. 19 (Order entered March 15, 2018) ("Temporary Rates Order").

Q. What was the impact on UGI of the Temporary Rates Order?

A. On May 17, 2018, at Docket No. R-2018-30000736, the Commission ordered each regulated utility currently not in a general base rate case proceeding, including UGI Utilities, Inc. Gas Division, UGI Central Penn Gas, Inc. and UGI Penn Natural Gas, Inc. (now UGI – South, UGI North, and UGI Central rate districts), to reduce their rates through the establishment of a temporary negative surcharge applied to bills rendered on or after July 1, 2018. As such, UGI reduced its rates by 5.78%, 3.90%, and 8.19%, for the customers served in what are now the UGI South, UGI North and UGI Central rate districts of UGI Gas, respectively. On December 1, 2018, the Company filed a reconciliation of the temporary negative surcharge rendered on bills to actual tax savings realized from the passage of the TCJA for the period July 1, 2018 through September 30, 2018. As a result of the reconciliation, the Company reduced the negative surcharge to 4.71%, 2.87%, and 6.34% for UGI South, UGI North, and UGI Central, respectively, which became effective on January 1, 2019.

In addition to implementing a temporary negative surcharge, the Commission also required Pennsylvania utilities to establish a regulatory liability for tax benefits that accrued during the period January 1, 2018 through June 30, 2018, resulting from the reduced corporate federal income tax rate. In response to the Order, UGI reduced its gross revenues and established a regulatory liability in the amount of $24,098,680. *See* UGI Gas Exhibit NMM-2.

Q. Has UGI reflected the impact of the TCJA in this proceeding?

A. Yes, the Company has reflected the impact of the TCJA in how it has calculated Schedules C-6, D-33 and D-34. I will describe how the Company has reflected the TCJA in greater detail in Sections D and E. Additionally, the testimony of Mr. David E. Lahoff (UGI Gas St. No. 8) explains the Company's proposal for crediting to its customers the tax savings realized for the period January 1, 2018 through June 30, 2018 for the reduction in the corporate federal income tax rate from 35% to 21%. UGI Gas Exhibit

NMM-3 provides a detailed calculation by month of the tax savings realized over this period, along with accrued interest.

C. INCOME TAXES

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

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

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

A. The calculation of federal and state income taxes can be found on Schedule D-33. Schedule D-33 shows the calculation of pro forma income taxes for the FPFTY at present and proposed rates. Line 1 shows the revenue at present and proposed rates, while line 2 shows the operating expenses at present and proposed rates from Schedule D-1. Line 3 reflects operating income before debt interest is deducted, by netting line 1 from line 2. Debt interest expense is synchronized using the rate base claim from Schedule C-1, with the cost of debt and the debt component of UGI's capital structure recommended in the direct testimony of Paul R. Moul (UGI Gas St. No. 5) and shown on Schedule B-7. The resulting interest expense on line 6 is subtracted from net income before debt interest to calculate base taxable income on line 7.

In accordance with established Commission practice, lines 8 through 11 of Schedule D-33 reduce the base taxable income, for state tax purposes, by the total difference between accelerated tax depreciation shown on line 8 and the pro forma book depreciation shown on line 9. The statutory state corporate net income tax rate (9.99%) was then applied to determine the pro forma state income tax expense shown on line 13. Lines 14 through 19 show the federal income tax expense calculation at current and proposed rates, while line 20 sums the state and federal tax expense amounts before application of Deferred Federal and State Income Taxes. At lines 21 through 28, Deferred Federal and State Income Taxes are used to increase the pro forma income tax expense at present and proposed rates with the total calculated amount for income taxes before the application of other adjustments shown on line 29. The amounts of accelerated depreciation, cost of removal, repairs tax deduction, tax basis adjustments to plant, straight line depreciation and book depreciation used in the determination of income taxes are summarized on Schedule D-34.

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

A. As shown on Schedule D-33 at line 31, the pro forma tax expense at present rates is $23.83 million and the pro forma tax expense at proposed rates for the FPFTY is $44.1

million. As explained below in Section G, this figure is not reduced by a consolidated income tax adjustment.

D. ACCUMULATED DEFERRED INCOME TAXES

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

A. Schedule C-6 shows the FPFTY ending balance for federal ADIT at September 30, 2020. This amount is deducted from rate base. The total shown on line 8 reflects the difference in income tax expense for book and tax purposes attributable to the difference between the accelerated tax depreciation, and straight-line book depreciation on test year plant balances, net of offsets associated with contributions in aid of construction. Rate base has been further reduced by the state regulatory liability associated with our repairs tax method shown on line 6. As the state tax consequence of accelerated depreciation is flowed through, there is no associated state ADIT balance.

Q. Was the calculation of ADIT impacted by the TCJA?

A. Yes. Beginning after September 30, 2018, the TCJA repealed "bonus depreciation" rules which would have permitted UGI to depreciate certain investments on a more accelerated basis than the regular Modified Accelerated Cost Recovery System ("MACRS'). The loss of bonus depreciation as a tax deduction significantly reduces UGI Gas's cash flow. The loss of this cash tax benefit will cause ADIT to grow at a slower pace than before. Further, the amount of such capital investments that must be financed by alternative means is likely to increase due to the loss of the cash tax benefit from bonus depreciation.

The enactment of the TCJA also created Excess Deferred Federal Income Taxes ("EDFIT") which is explained in further detail below in Section E.

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

A. As shown on line 8 of Schedule C-6 and on line 6 of Schedule A-1, the ADIT offset is $574.78 million, which includes an amount related to EDFIT as explained below in Section E and the repairs tax method explained below in Section F.

Q. Has the Company's ADIT rate base deduction been calculated in compliance with the normalization requirements of the Internal Revenue Code?

A. Yes. The Company's calculation properly reflects the pro-rationing concept in accordance with Treasury Regulation 1.167(l)-1(h)(6)(ii) that it must follow for ratemaking purposes to be in compliance with IRS normalization requirements. The pro-rationing concept requires that utilities pro-rate their rate base ADIT deduction to account for the time during the fully projected future test year that the ADIT for plant additions will be accrued by the company. This pro-rata calculation is required by the IRS in order for a utility company to be permitted to use accelerated depreciation and not have a normalization violation. As such, the Company reflects a pro-rationing of the ADIT associated with its FPFTY plant additions. This method is consistent with the Company's past ratemaking practice and has been accepted by the Commission in the Company's past base rate proceedings.

E. EXCESS DEFERRED FEDERAL INCOME TAXES

Q. Why are excess deferred federal income taxes ("EDFIT") being calculated as part of this proceeding?

A. Under Accounting Standards Codification ("ASC") 740, public companies record ADIT to represent the future tax consequences of events occurring today. Temporary or "timing" differences give rise to ADIT. These timing differences represent the difference between when an item is recognized for book/GAAP purposes versus tax purposes. ASC 740 requires ADIT to be recorded using the tax rate expected to be in effect when the temporary difference reverses. Stated another way, ADIT is required to be reported at the amount expected to be due to the federal government or other taxing authority when the temporary difference reverses. Through December 21, 2017, the Company's ADIT was measured at 35% because that was the expected federal tax rate when the temporary differences would reverse. As a result of the TCJA, the federal tax rate became 21%. Thus, future temporary differences are now expected to reverse at 21%. Due to the change in the federal tax rate, ADIT was re-measured such that ending ADIT balances for GAAP purposes were at the new 21% federal tax rate. The difference in the ADIT balance from when it was at a 35% tax rate to its new 21% tax is EDFIT. The EDFIT represents that taxes are no longer due at the 35% federal tax rate; rather, they are due at the new 21% tax rate. The Company has reduced its rate base by EDFIT, which is incorporated in the ADIT balance on Line 8 of Schedule C-6.

Q. Has the Company reflected the amortization of the EDFIT on its income tax claim?

A. Yes, the Company has calculated the amount of the EDFIT that would be amortized and flowed back to ratepayers in its FPFTY. This amount is included in the overall federal deferred tax expense calculated on Line 25 of Schedule D-33. The total amortization was approximately $3.81 million, calculated using the Average Rate Assumption Method ("ARAM") as required by tax normalization rules.

F. REPAIRS TAX METHOD

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

A. As has been accepted in past cases, UGI has chosen to calculate its federal income tax expense claim, inclusive of the repairs tax deduction, consistent with normalization. As a result, the difference between using accelerated tax depreciation versus book depreciation in the calculation of federal tax expense creates ADIT. For state income tax purposes, solely with respect to the repairs tax deduction, UGI has chosen to flow-through the repairs tax benefit over the tax useful lives of the assets generating the tax deduction. The state ADIT balance associated with the repairs tax deduction is classified as a regulatory liability, as it represents the repairs tax benefit that ratepayers have not yet received. In both the federal and state instances, the ADIT balance amortizes or unwinds over the remaining life of the asset.

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

G. CONSOLIDATED TAX BENEFITS

Q. Has the Company calculated a consolidated tax expense adjustment?

A. Yes, but not for the purpose of flowing through as a ratemaking deduction to federal income tax expense. It is my understanding that Act 40 of 2016, which added 66 Pa. C.S § 1301.1 to the Public Utility Code, prohibits the use of a consolidated tax adjustment for ratemaking purposes. However, Section 1301.1(b) requires a public utility seeking to change rates to demonstrate that it uses at least 50 percent of what would have been a consolidated tax expense adjustment under the law prior to Act 40 for reliability or infrastructure related capital investment and the other 50 percent must be used for general corporate purposes. I have included a calculation of such an adjustment using the modified effective tax rate methodology traditionally used by the Commission prior to the enactment of Act 40 as UGI Gas Exhibit NMM-4 which indicates a consolidated tax adjustment in the amount of $851,000. Company witness Mr. Stephen F. Anzaldo (UGI Gas St. No. 3) discusses how the Company's capital budgets satisfy the requirements of Act 40.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS EXHIBIT NMM-1

Nicole M. McKinney, CPA

79 Landis Drive
Lancaster, PA 17602
(717) 330-9138
nrispress@gmail.com

PROFESSIONAL EXPERIENCE:

UGI Utilities, Inc. Reading, PA
Manager. March 2015 – Present

- Supervise 2 direct reports
- Manage the accounting for income taxes in accordance with ASC 740 and regulated operations under ASC 980
- Provide technical accounting guidance and expertise on regulatory accounting and compliance and income tax matters
- Manage the preparation of various regulatory and income tax related filings

DENTSPLY International. York, PA
Manager. August 2012 –April 2014

- Supervised staff of 3
- Responsible for identifying deficiencies and areas of improvement for current tax and accounting processes
- Managed completion of domestic federal tax returns and income tax provision
- Performed periodic presentations to senior management regarding tax implications of various business transactions and changes in tax law
- Supervised special tax projects such as research & development tax credit study, domestic production activities deduction, and accounting method changes

ParenteBeard, LLC. Lancaster, PA
Manager. December 2010 – July 2012.

- Supervised staff of 5
- Managed client relationships for middle-market businesses to ensure satisfaction of tax and accounting needs
- Assisted in the standardization of accounting processes and working papers
- Served as the liaison between external auditors and clients to achieve efficiency and successful results in year- end audits
- Reviewed complex individual, partnership, corporate, and international federal and state tax returns
- Served as manager on the strategic tax initiative team

WTAS, LLC. Philadelphia, PA
Manager. August 2006 – November 2010.

- Supervised staff of 3+
- Managed successful consulting engagements resulting in substantial cash savings
- Developed various complex financial models for client budgetary and forecasting needs
- Prepared and reviewed various international, domestic, and state corporate and partnership tax returns

EDUCATION:

Villanova University, Villanova, PA
Master of Accountancy - May 2007
Bachelor of Science - International Business/Management & Accounting - May 2006
Summa cum Laude
Bartley Medallion of Honor

UGI GAS EXHIBIT NMM-2

UGI Utilities, Inc. - Gas Division
Impact of Tax Cuts & Jobs Act ("TCJA")
January 1, 2018 - June 30, 2018

Pre TCJA Taxes		Net Tax Effect
Total Tax Expense (Current + Deferred)	$	59,075,676
Less: Post TCJA Taxes		
Total Tax Expense (Current + Deferred)	$	41,134,643
Effect of TCJA On Income (A)	$	17,941,032
Change in ADIT	$	596,987
Implied Commission Approved Rate of Return		8.31%
Effect of ADIT Change on Income (B)	$	49,610
Earnings Change (Line A - Line B)	$	17,891,423
Complement of Tax Rate	$	0.7111
Revenue Conversion (Increase)/Decrease	$	25,160,949
Amount Previously Given Back to Customers	$	1,132,036
Remaining Revenue Give Back/(Collection)	$	24,028,914
Accrued Interest Expense/(Income)	$	2,219,592
Total Revenue Give Back/(Collection)	**$**	**26,248,506**
Base Customer Charge Revenue (excludes PGC, USP and EEC)	**$**	**582,984,553**
Proposed Surcharge Effective with the Implementation of new new base rates over a 12-month recovery period.period.		**4.50%**

UGI Utilities, Inc. - Gas Division

Impact of Tax Cuts & Jobs Act ("TCJA")

January 1, 2018 - June 30, 2018

	18-Jan	**18-Feb**	**18-Mar**	**18-Apr**	**18-May**	**18-Jun**	**Total**
Earnings Before Taxes ("EBT')	56,138,369	30,548,855	39,005,380	19,263,414	(1,503,754)	(1,078,938)	142,373,325
Change in Tax Rate	-12.60%	-12.60%	-12.60%	-12.60%	-12.60%	-12.60%	
Actual Tax (Savings)/Loss	(7,074,220)	(3,849,583)	(4,915,224)	(2,427,460)	189,494	135,961	(17,941,032)
Gross-Up Conversion	1.406313504	1.406313504	1.406313504	1.406313504	1.406313504	1.406313504	
Required Give-(Back)/Collection	(9,948,572)	(5,413,721)	(6,912,346)	(3,413,770)	266,488	191,204	(25,230,716)
Actual Give (Back)/Collection via Bill Credit	0	0	0	0	0	(1,132,036)	(1,132,036)
(Under)/Over Give-Back Bfr Interest	(9,948,572)	(5,413,721)	(6,912,346)	(3,413,770)	266,488	1,323,240	(24,098,680)
Interest Rate	**5.5%**	**5.5%**	**5.5%**	**5.5%**	**5.5%**	**5.5%**	
Interest Weighting Ratio	**175%**	**167%**	**158%**	**150%**	**142%**	**133%**	
Total Accrued Interest (Expense)/Income	(957,550)	(496,258)	(601,950)	(281,636)	20,764	97,038	(2,219,592)
Total (Under)/Over Give Back	**(10,906,122)**	**(5,909,979)**	**(7,514,296)**	**(3,695,406)**	**287,252**	**1,420,277**	**(26,318,273)**

Pre - TCJA ADIT	32,899,519
Post - TCJA ADIT	32,302,532
Change in ADIT	**596,987**

UGI GAS EXHIBIT NMM-3

UGI Utilities, Inc. - Gas Division
Calculation of Pro-Rata Accumulated Deferred Income Tax
(In Thousands)

Month	A Increase to Deferred Taxes	B # of Days	C = B/365 Pro-Rata %	D = C*A Pro-Rata Incr to Deferred Taxes	Per Treas. Reg.1.167(l)-1(h)(6)(ii) Accumulated Deferred Income Tax Balance
9/30/2019					$ 569,641
10/31/2019	596	335	91.78%	547	570,189
11/30/2019	682	305	83.56%	570	570,758
12/31/2019	1,443	274	75.07%	1,083	571,842
1/31/2020	1,663	243	66.58%	1,107	572,949
2/28/2020	870	215	58.90%	512	573,461
3/31/2020	849	184	50.41%	428	573,889
4/30/2020	636	154	42.19%	268	574,158
5/31/2020	765	123	33.70%	258	574,416
6/30/2020	687	93	25.48%	175	574,591
7/31/2020	448	62	16.99%	76	574,667
8/31/2020	1,225	31	8.49%	104	574,771
9/30/2020	3,998	1	0.27%	11	**$ 574,782**

UGI GAS EXHIBIT NMM-4

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

	Taxable Income 2015	Taxable Income 2016	Taxable Income 2017	Average	
Tax Loss Entities					
Ashtola Production Company	(1)	(1)	(1)	(1)	
Hellertown Pipeline	(23)	(2)	0	(8)	
Homestead Holding	(16)	(126)	(199)	(114)	
UGI Development Company	(6,170)	0	0	(2,057)	
UGI HVAC Enterprises	(1,327)	(350)	(541)	(739)	
UGI LNG	(261)	(706)	0	(322)	
UGI Petroleum Products of DE	(139)	(0)	0	(46)	
UGID Holding Company	(8)	(8)	(8)	(8)	
United Valley Insurance	(339)	(3,295)	0	(1,211)	
UGI Corporation	0	(11,488)	(8,138)	(6,542)	
AmeriGas Inc	0	(20)	(32)	(17)	
UGI China Inc	0	0	0	0	
UGI International China. Inc	0	(252)	(199)	(150)	
UGI Penn HVAC Services	0	(170)	(226)	(132)	
UGI Enterprises Inc	0	0	(18,583)	(6,194)	
Total Tax Loss	(8,283)	(16,417)	(27,926)	(17,542)	
Tax Positive Entities					% of Total
AmeriGas Propane Inc.	55,822	50,168	50,831	52,274	18.5%
AmeriGas Inc.	449	0	0	150	0.1%
Amerigas Technology Group Inc.	1	0	0	0	0.0%
Energy Service Funding	3,788	2,576	3,730	3,365	1.2%
Newberry Holding	517	640	1,450	869	0.3%
Petrolane Incorporated	16,679	16,801	0	11,160	4.0%
UGI Central Penn Gas	21,902	10,388	13,958	15,416	5.5%
UGI China, Inc.	1,192	0	967	720	0.3%
UGI Corporation	2,231	0	0	744	0.3%
UGI Development Company	0	4,323	259	1,527	0.5%
UGI Enterprises, Inc.	97,540	89,121	0	62,220	22.1%
UGI Europe, Inc.	104,060	86,109	101,813	97,327	34.5%
UGI LNG	0	0	4,941	1,647	0.6%
UGI Penn HVAC Services	876	0	0	292	0.1%
UGI Properties, Inc.	172	28	347	182	0.1%
UGI Storage Company	7,276	6,703	5,646	6,542	2.3%
UGI Utilities, Inc.	42,897	0	0	14,299	5.1%
UGI International Enterprises, Inc.	1,178	0	0	393	0.1%
UGI Penn Natural Gas	34,986	0	0	11,662	4.1%
United Valley Insurance	0	0	2,415	805	0.3%
Eliminations	353	313	213	293	0.1%
Subtotal Taxable Income	391,919	267,170	186,569	281,886	100.0%
Total	**383,636**	**250,753**	**158,643**	**264,344**	

Tax Savings Applicable to UGI Utilities, Inc.	(890)
MWF Allocation % for UGI South	83.93%
Tax Savings Applicable to UGI South	(747)
Tax Savings Applicable to UGI Central	(959)
Tax Savings Applicable to UGI North	(726)
Total Tax Savings Allocated to UGI Gas	(2,432)
Federal Tax Rate	35%
Total Consolidated Tax Adjustment	**(851)**

Note, single-member limited liability companies, i.e. disregarded entities, have been combined with their tax-regarded parent company.

	Taxable Income 2016	Adjustments		Adjusted Taxable Income
Tax Loss Entities				
UGI Corporation	(20,139)	8,652	(1)	(11,488)
AmeriGas Inc	(20)			(20)
Amerigas Technology Group Inc.	-			0
Ashtola Production Company	(1)			(1)
Eastfield International Holdings Inc	-			0
EuroGas Holdings Inc.	-			0
Four Flags Drilling Company	-			0
Hellertown Pipeline	(2)			(2)
Homestead Holding	(126)			(126)
UGI Asset Management	-			0
UGI Black Sea Enterprises	-			0
UGI China Inc	(3,868)	3,868	(2)	0
UGI Energy Ventures, Inc.	-			0
UGI Ethanol Development Company	-			0
UGI Hunlock Dev	-			0
UGI HVAC Enterprises	(350)			(350)
UGI International China. Inc	(252)			(252)
UGI International (Romania)	-			0
UGI LNG	(706)			(706)
UGI Penn HVAC Services	(170)			(170)
UGI Petroleum Products of DE	(0)			(0)
UGI Romania, Inc.	-			0
UGID Holding Company	(8)			(8)
United Valley Insurance	(3,295)			(3,295)
Total Tax Loss	(28,937)	12,520		(16,417)

Notes:

(1) Adjust to remove impact of expense due to above normal exercise of stock options.

(2) Adjust to remove discontinued operations

UGI GAS STATEMENT NO. 12 – ANGELINA M. BORELLI

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3006814

UGI Utilities, Inc. – Gas Division

Statement No. 12

Direct Testimony of
Angelina M. Borelli

Topics Addressed:	**Merger Settlement Compliance Activities** **Scheduled Delivery Confirmation Processes and Communication Changes** **Unified Choice and Non-Choice Transportation Rules** **Unified Gas Supply Portfolio and Purchased Gas Cost Rate** **Gas Information System Website Upgrade**

Dated: January 28, 2019

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Angelina M. Borelli. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

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

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

Q. What are your principal duties and responsibilities as Director – Gas and Electric Supply?

A. As Director – Gas and Electric Supply, I am responsible for gas and electric supply planning, procurement, and scheduling for UGI Electric and UGI Gas. In the case of UGI Gas, this responsibility includes, but is not necessarily limited to:

- Overseeing the procurement, pursuant to a statutory least-cost procurement standard, of a portfolio of natural gas supply assets needed to ensure the deliverability of natural gas supplies to UGI Gas's system to meet the needs of UGI Gas's smaller volume customers for which UGI Gas has a statutory supplier-of-last-resort ("SOLR") obligation under Section 2207 of the Public Utility Code ("Core Market Customers").

- Helping develop and administer nomination and delivery requirements for Commission-licensed natural gas suppliers ("NGSs") serving pools of Core Market Customers ("Choice Suppliers") on UGI Gas's system that elect to procure natural gas supply services from such Choice Suppliers ("Choice Customers"), and administer the release and recall of gas supply assets or their functional equivalents to Choice Suppliers as Choice Customers join or leave Choice Supplier pools.
- Where approved by the Commission, overseeing the procurement and release of interstate pipeline capacity, on either a mandatory or voluntary basis, to certain transportation customers for which UGI Gas does not have SOLR responsibility (generally "Transportation Customers" or "Non-Choice Transportation Customers"), to help ensure the reliability of system deliveries.
- Helping establish and administer delivery parameters for Transportation Customers to ensure that UGI Gas's system, and each of its segments, can successfully operate in a reliable manner by balancing end-use customer withdrawals with system deliveries to available delivery paths.
- Overseeing UGI Gas's natural gas supplier collaborative process and communications with NGSs.
- Procuring natural gas supply assets needed to handle allowable variations between NGS or Transportation Customer end deliveries into and withdrawals from UGI Gas's system.
- Overseeing the procurement and delivery of natural gas to Core Market Customers who do not elect to or cannot procure their natural gas supply services from a Choice Supplier ("PGC Customers").

- Overseeing UGI Gas's preparation and filing of annual purchased gas cost ("PGC") filings pursuant to Section 1307(f) of the Public Utility Code and associated administrative proceedings before the Commission.

Q. What is your educational background?

A. Please see my resume that is attached as UGI Gas Exhibit AMB-1.

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

A. Yes. Please see UGI Gas Exhibit AMB-1 for the specific Docket numbers.

Q. What is the purpose of your testimony?

A. My testimony will address: (1) merger settlement compliance activities; (2) scheduled delivery confirmation process and communications changes; (3) proposed unified Choice and Non-Choice Transportation rules; (4) the proposed unified gas supply portfolio and PGC rate; and (5) the proposed Gas Information System ("GIS") website upgrade and associated cost estimate.

II. MERGER SETTLEMENT

Q. Please describe UGI Gas's recent merger.

A. Prior to October 1, 2018, UGI Gas owned two subsidiaries which were Commission-certificated NGDCs. Those subsidiaries were: (1) UGI Penn Natural Gas, Inc. ("UGI PNG"), which began its operations following the close, on August 24, 2006, of UGI Corporation's purchase of the natural gas distribution assets from the former PG Energy Division of Southern Union Company, as authorized by a Commission Order entered on

August 18, 2006, at Docket No. A-120011F200; and (2) UGI Central Penn Gas, Inc. ("UGI CPG"), formerly PPL Gas Utilities Corporation, acquired by UGI Gas effective October 1, 2008, as authorized by a Commission Order entered on August 21, 2008, at Docket Nos. A-2008-2034045 *et al*. On March 8, 2018, UGI Gas (now comprising the UGI South Rate District), UGI PNG (now comprising the UGI North Rate District) and UGI CPG (now comprising the UGI Central Rate District) filed a petition with the Commission to merge UGI PNG and UGI CPG into UGI Gas, and to thereafter operate as a single natural gas distribution company with three rate districts adopting the three former tariffs of UGI Gas, UGI PNG and UGI CPG, respectively. A Joint Petition for Approval of Settlement of All Issues ("Merger Settlement") was subsequently submitted to the Commission. In an Opinion and Order entered on September 20, 2018 at Docket Nos. A-2018-3000381, A-2018-3000382 and A-2018-3000383 ("Merger Order"), the Commission approved the Merger Settlement with certain revisions not opposed by any party. Consistent with the authority granted in the Merger Order, the merger was completed on October 1, 2018 and UGI Gas commenced operations under the three-rate district structure described above.

Q. Under the Commission-approved Merger Settlement, did UGI Gas and others agree to take certain actions concerning Choice and Non-Choice transportation service?

A. Yes, the Merger Settlement included, amongst other things, the following terms:

16. On or before September 30, 2018, UGI, the NGS Parties and other interested parties will meet and initiate the collaborative process for the purpose of *developing an initial strawman uniform gas choice and non-choice transportation programs proposal. The following issues will be addressed:*

(a) Establishing uniformity of rules in each of the consolidated UGI Gas Division rate districts governing choice and, separately, non-choice transportation programs.

(b) Scheduled delivery confirmation process and communication.

(c) Imbalance Cash-out provisions.

(d) Cost recovery associated with program rule changes and additional facilities or equipment, including but not limited to recovery of the costs of information system modification necessitated by the program changes.

17. In conjunction with the collaborative process provided in Paragraph No. 16., above, no later than February 28, 2019 or such later date as the parties to the collaborative may agree, either as part of a base rate proceeding or as a limited purpose tariff filing before the Commission, UGI shall propose uniform rules governing the gas choice and non-gas choice transportation programs throughout the UGI Gas service territory. As part of the filing, UGI will state whether all parties to the collaborative process concur with the filing and shall serve a copy of the filing on each participant in the collaborative process. To the extent that parties do not agree with any provisions, those parties shall retain all rights to challenge the tariff filing.

III. <u>SCHEDULED DELIVERY CONFIRMATION PROCESSES AND COMMUNICATION CHANGES</u>

Q. What actions did UGI Gas take to comply with Paragraph 16(b) of the Merger Settlement addressing scheduled delivery confirmation processes and communication?

A. I oversaw an internal project which reviewed current scheduled delivery confirmation processes and communications. The project was initiated in early 2018 when the Company sought to enhance the timeliness of scheduled delivery information availability to NGSs. As a result of this effort UGI Gas:

- Developed revised standardized nomination and confirmation procedures and communications protocols reflected in UGI Gas Exhibit AMB-2 to my testimony and implemented these changes in the summer of 2018.
- Conducted two webinars in August of 2018 to review the revised procedures and communications protocols and to answer questions, and posted the revised procedures and communications protocols on UGI Gas's GIS website.
- Updated after-hours contact information and provided a monthly on-call schedule on UGI Gas's GIS website.

UGI Gas also reviewed these changes and solicited feedback from interested persons at a collaborative conducted in Reading on September 30, 2018. Notice of this collaborative was provided to all Pennsylvania licensed NGSs and known interested parties by U.S. postal mail, email, and posts on the Company's GIS website. Twenty-six participants from eighteen different organizations elected to participate in the September 30, 2018 collaborative meeting, either by telephone or in person. No feedback or suggestions concerning the above-described changes was received during the collaborative or through other means thereafter. As a result, no further revisions to UGI Gas's revised scheduled delivery confirmation processes and communications were deemed necessary.

IV. UNIFIED NON-CHOICE TRANSPORTATION RULES

Q. What actions has UGI Gas taken to comply with Paragraphs 16(a) and 17 of the Merger Settlement with respect to Non-Choice Transportation rules?

A. I led an internal team that initially reviewed the reliability requirements of a unified UGI Gas system, and that identified discrepancies in Non-Choice Transportation rules and practices between rate districts and considered potential solutions. After completing this internal review, the team then developed an initial strawman proposal for unified Non-Choice Transportation rules that was presented at the September 30, 2018 collaborative. Various aspects of the strawman proposal were discussed and questions about the proposal were answered.

Q. Did UGI Gas provide the parties with an opportunity to comment on the proposal?

A. Yes. I encouraged participants to provide feedback or alternative proposals both during and after the collaborative. A summary of the comments, suggestions, and Company responses are included as UGI Gas Exhibit AMB-3 to my testimony. These suggestions and comments will be addressed later in my testimony.

Q. Please describe the Company's current delivery requirements for Non-Choice Transportation Customers.

A. The Company requires large transportation customers to deliver natural gas supplies at points of interconnection between each of the Company's Rate Districts and its upstream natural gas suppliers, which include interstate pipelines, local natural gas production wells, gathering systems, and peak-shaving facilities. The Company currently maintains separate delivery rules for each Rate District. A summary of the Company's current delivery requirements can be found in UGI Gas Exhibit AMB-4.

Q. Why should the current delivery requirements for Non-Choice Transportation Customers change under a uniform transportation program?

A. There is an opportunity to consolidate delivery requirements and reduce administration for NGSs and the Company by developing a uniform transportation program. For example, each of the Company's three Rate Districts receives natural gas supply deliveries and maintains separate delivery requirements for the Transcontinental Gas Pipe Line Company, LLC ("Transco"). An NGS operating on each of the Company's Rate Districts is required to manage the daily forecasting, procurement, and scheduling separately for its customers on each Rate District. Under a uniform program, the opportunity exists to consolidate this activity and manage these three separate customer groups as one.

Q. Please describe the Company's proposed changes to Non-Choice Transportation delivery requirements.

A. In reviewing the reliability requirements of a unified UGI Gas system, and being mindful of the fact that reducing the number of customer regions NGSs are required to manage could be beneficial to such NGSs, UGI Gas proposed to reduce the number of regions having differing delivery requirements from twelve to four, reflecting gas delivery capabilities without regard to existing rate district boundaries, and proposed delivery rules for each of these four regions. The regions and delivery requirements proposed at the collaborative are shown in UGI Gas Exhibit AMB-5 to my testimony.

Q. When does UGI Gas propose to implement its new delivery regions and associated delivery rules?

A. UGI Gas proposes to implement its new delivery regions and associated delivery rules on November 1, 2020. During the collaborative process, some of the parties requested that the Company delay implementation of the proposed delivery rules in order to provide NGSs sufficient time to adjust their supply portfolios. This delayed implementation date will also provide the Company time to make business process and programming changes to its information systems, including the GIS upgrades discussed below, to facilitate implementation of the new rules.

Q. As a result of feedback received through the collaborative process has UGI Gas made any modifications to the proposed delivery requirements it presented at the September 30, 2018 collaborative?

A. Yes. UGI Gas proposes to split one of its initially proposed delivery regions and is accordingly proposing to establish five delivery regions, with associated delivery requirements, commencing November 1, 2020.

Q. Why has UGI Gas proposed to establish a fifth delivery region?

A. The Company's initial proposal included a Texas Eastern Market Area 3 and Columbia Operating Area 8 delivery requirement for customers located in the Southwest region. During the collaborative process, however, some participants advocated splitting the proposed Southwest region into two separate customer regions: one requiring deliveries on Texas Eastern, Market Area 3, and the other on Columbia Market Area 8. Since the Company initially proposed to establish only four delivery regions to reduce the burden on NGSs of administering different delivery regions, but certain NGSs believe there are more than offsetting benefits from the establishment of a fifth region, the Company has adopted this suggestion.

Q. Did the Company receive any other requests about customer regions?

A. Yes. The Company also received a request to provide a convenient method for NGSs to identify a customer's or prospective customer's delivery region. The Company has agreed, and proposes to post a list of customer account numbers and corresponding customer regions on its GIS website that would be available to NGSs after submitting their login information.

Q. Please describe the Acceptable Substitute delivery sources.

A. The Company's proposal requires transportation customers to make deliveries on the major interstate pipelines that deliver into its service territory: Texas Eastern Transmission, LP ("Texas Eastern"), Tennessee Gas Pipeline, LLC ("Tennessee"), Transcontinental Gas Pipeline Company, LLC ("Transco"), and Columbia Gas Transmission ("TCO" or "Columbia"). In addition to these major supply sources, the Company receives natural gas supplies from local production wells, gathering systems, and other pipelines. The Company proposes that these additional supply sources ("Acceptable Substitutes") may be used to fulfill a required interstate pipeline delivery. A summary of the Acceptable Substitutes is attached as UGI Gas Exhibit AMB-6 to my testimony.

Q. Were any comments or suggestions received related to the Acceptable Substitutes?

A. Yes. The Company received comments from two parties expressing concern that some of the Available Substitutes are owned by UGI Gas's affiliate, UGI Energy Services, LLC ("UGIES"). These parties believe that permitting deliveries from these supply sources will provide UGIES with a competitive retail marketing advantage.

Q. What is the Company's position related to the Acceptable Substitutes?

A. I believe that it is important to make all supply delivery options that are operationally feasible available to customers, and do not believe it would be appropriate for the Company to try to alter the competitive advantages or disadvantages of certain marketers by excluding available supply sources.

Q. How would daily balancing requirements change under UGI Gas's proposal?

A. Attached as UGI Gas Exhibit AMB-7 to my testimony is a summary of the current firm daily balancing tolerances by rate district which UGI Gas provides to Non-Choice Transportation Customers to help them manage daily balancing limits. Currently, daily imbalances of up to ten percent (10%) are permitted in the UGI South Rate District, whereas imbalances of up to two and one-half percent (2.5%) are permitted in the UGI North and Central Rate Districts. UGI Gas proposes to merge this balancing service with the formerly optional Rate NNS service into a unified daily balancing service with a firm four and one-half percent (4.5%) daily balancing tolerance. The revised firm four and one-half percent (4.5%) threshold reflects a weighted average of current firm daily imbalance allowances, which means that when UGI Gas is managing daily imbalances system-wide it should not need to procure any meaningful new gas supply resources to handle such swings above current aggregate levels. Transportation Customers may also elect an optional interruptible service under a unified Rate NNS (No-Notice Service) up to their Daily Firm Requirement or Maximum Daily Quantity (UGI Gas Exhibit F – Proposed Tariff). UGI Gas witness David E. Lahoff (UGI Gas St. No. 8) addresses the calculation of a new unified rate for service elected under Rate NNS.

Q. Were any other suggestions received related to daily balancing?

A. Yes. Some of the parties to the collaborative process suggested that UGI Gas provide a firm ten percent (10%) daily balancing tolerance to all transportation customers.

Q. Is the Company proposing to adopt this suggestion in this filing?

A. No. A four and one-half percent (4.5%) balancing tolerance, based on a weighted average of the current daily balancing tolerances, will allow the Company to manage its system using existing gas supply assets. Establishing a ten percent (10%) daily balancing tolerance would require the Company to find and acquire incremental gas supply assets on short notice. It would also require the Company to address how these incremental costs would be recovered. Given these constraints, the Company believes its proposal is the most reasonable means of managing the transition to an initial uniform daily imbalance tolerance.

Q. How would monthly balancing requirements change under UGI Gas's proposal?

A. UGI Gas's imbalance and cash-out provisions were reviewed in the context of its development of proposed unified Choice and Non-Choice Transportation rules and were reviewed during the September 30, 2018 collaborative. The Company does not propose any changes to the monthly balancing tolerances, which are currently set at ten percent (10%) for each Rate District. As shown in UGI Gas Exhibit F, UGI Gas proposes to adopt revised indices for each of the five proposed delivery regions to reflect the market realities of these separate geographic areas in compliance with Paragraph 16(c) of the Merger Settlement.

Q. Has the Company received any substantive suggestions related to the cash-in or cash-out indices?

A. Yes. The Company received a suggestion to provide a Columbia index in addition to Texas Eastern for the Southeast and Southwest region, corresponding to the regions' delivery requirements on both pipelines.

Q. Is the Company proposing to adopt this suggestion to provide a Columbia index for cash-in and cash-out on the Southeast and Southwest regions?

A. No. The Company is not proposing to provide a Columbia-related index as there currently is no available published index for Columbia deliveries in the area of the Company's distribution system. It is my opinion that the Texas Eastern Market Area 3 index is the most representative of gas prices in the area of the Company's distribution system.

Q. How does UGI Gas propose to handle capacity releases to Non-Choice Transportation Customers?

A. UGI Gas currently provides capacity releases to certain Non-Choice Transportation Customers in its North and South Rate Districts. Attached as UGI Gas Exhibit AMB-8 to my testimony is a summary of the existing capacity release rules for Rate LFD and Rate DS Transportation customers and the Company's proposed uniform rules. The proposed uniform rules essentially adopt rules prevailing in the current North Rate District and extend them to areas encompassed in the current South and Central Rate Districts as well. These rules help smaller transportation customers obtain access to primary firm transportation capacity and help UGI Gas ensure that large numbers of smaller volume customers will not violate balancing tolerances (and potentially need to be physically disconnected from the UGI Gas system to maintain system reliability) in the event interstate pipeline deliveries to secondary delivery points are curtailed, which is an increasingly common occurrence.

Q. How does the Company currently recover the cost of capacity releases to Rate LFD Customers?

A. The cost of capacity released to Rate LFD customers is recovered through the capacity release mechanism.

Q. How does UGI Gas propose to recover the cost of capacity from Rate LFD customers under a uniform capacity release program?

A. The Company currently utilizes the same method of recovering the costs for capacity from Rate LFD customers in both the North and South Rate Districts. The Company proposes, on a Company-wide basis, to employ this same method to customers currently located in the Central Rate District.

Q. How does the Company currently recover the cost of capacity releases to Rate DS Customers?

A. Rate DS customers in UGI's North Rate District currently pay a capacity charge ("Capacity Charge") equal to the District's unitized weighted average cost of firm transportation capacity. This rate is assessed on the Rate DS customer's Maximum Daily

Quantity ("MDQ"), which is elected by each Rate DS customer in their service agreement. The elected MDQ defines the Company's maximum firm delivery obligation and is initially established to reflect the expected maximum usage of each customer's gas-burning equipment. Over time it may be adjusted as new equipment is added or subtracted, or be adjusted based on readings from the daily metering facilities installed at each UGI North Rate District service location. Unlike the UGI North Rate District, Rate DS customers in the UGI South Rate District have historically not had daily metering facilities. Perhaps reflecting the lack of daily metering facilities, these customers currently do not have a MDQ defined in their service agreements; the rate these customers have paid for capacity has been charged on a volumetric basis, rather than an MDQ basis, using a methodology established in the former UGI Gas's 1995 base rate proceeding at Docket No. R-00953297. The Company currently does not release capacity to customers located in the Central Rate District.

Q. How does UGI Gas propose to charge Rate DS customers for capacity in the current proceeding?

A. The Company proposes, on a Company-wide basis, to employ the UGI North Rate District method of multiplying the weighted average cost of capacity times each Rate DS customer's MDQ. In the case of current UGI South Rate District customers, this will require the Company to develop MDQs for all Rate DS customers for the first time. To ease implementation, UGI Gas proposes to use the same algorithm that is used to predict the firm peak requirements for Choice Customers. Rate DS customers' usage history is maintained in the same information system as those of the Choice Customers, and the functionality exists within this system to forecast a design requirement for the Rate DS customers without additional system programming. The Company proposes to use the forecasted firm peak requirements as an initial MDQ which will be communicated individually to all Rate DS customers. The Company will thereafter work with Rate DS customers to incorporate MDQs into their service agreements. Future MDQ calculations will also have the benefit of readings from daily metering facilities which the Company is proposing to install on all Rate DS customer accounts in areas currently encompassed in the UGI South Rate District. The proposed installation of daily metering facilities on all Rate DS accounts in what is now the UGI South Rate District is discussed in the testimony of UGI Gas witness Shaun M. Hart (UGI Gas St. No. 9).

Q. Were these capacity release proposals reviewed as part of the September 30, 2018 collaborative meeting?

A. Yes, I shared these proposed changes and solicited feedback from interested persons at the collaborative meeting on September 30, 2018. No substantive comments or suggestions were received during or after the meeting. I believe this reflects a general consensus that these proposals are fair and appropriate.

Q. When does UGI Gas propose to make these new Non-Choice Transportation Customer capacity release rules effective?

A. They are proposed to become effective upon the conclusion of this proceeding, which is expected to occur in October of 2019.

V. UNIFIED CHOICE TRANSPORTATION RULES

Q. What actions has UGI Gas taken to comply with Paragraphs 16(a) and 17 of the Merger Settlement with respect to Choice Transportation rules?

A. Since Choice Customers do not have metering facilities capable of measuring their daily use, each of the UGI Gas rate districts currently uses algorithms to calculate the anticipated daily demand of each Choice Customer pool (the "Daily Delivery Requirement" or "DDR") which is provided to each Choice Supplier. The Choice Supplier then has an obligation to nominate and deliver supplies equal to the DDR to the applicable rate district. Under current rules prevailing across all of UGI Gas's rate districts, Choice Suppliers receive from UGI Gas a release or sale of gas supply assets, or their functional equivalent, in an amount equal to the peak day requirements of the Choice Customers they serve, and NGSs are then free to either use those assets or alternative assets to deliver DDR quantities. If the calculated use of Choice Customers under the algorithm subsequently differs from the DDR amount (primarily because of unexpected temperature or weather variations from those used to calculate the DDR) UGI Gas manages the difference. In the case of the UGI South Rate District, DDR deliveries by Choice Suppliers are required on all of the major interstate pipelines serving the UGI South service territory; in the case of the UGI North and UGI Central Rate Districts, DDR deliveries must be made to delivery points in specified regions.

In response to the Merger Settlement, I oversaw a team that looked at existing Choice rules and how they might be modified to develop a strawman proposal for unified Choice rules. We concluded that the existing Choice framework works well and modeled the delivery rules after the UGI South Rate District program where Choice Suppliers are required to make deliveries on all of the major interstate pipelines serving the Company and have access to the Company's supply assets across these pipelines. We also concluded that the mixture of assets released or sold to Choice Suppliers to meet the peak-day requirements of their Choice Customers would change under a uniform system-wide gas supply plan. We also concluded that reliability standards could be maintained by giving Choice Suppliers the flexibility to deliver their DDR quantities at any pipeline delivery point on the unified UGI Gas system. Thus, at the September 30, 2018 collaborative, UGI Gas proposed to carry-over existing Choice rules with the modifications noted above and provided examples of the expected mix of released or sold gas supply assets, or their functional equivalent, that would result from a uniform system-wide gas supply plan and Choice rules. Various aspects of the strawman proposal were discussed and questions about the proposal were answered. No substantive comments or suggestions were received. I believe this reflects a general consensus that the strawman proposal is fair and appropriate. Accordingly, that proposal has been reflected in the proposals in this filing, and UGI Gas proposes to implement the new rules as of the effective date of the new rates established in this proceeding.

VI. UNIFIED GAS SUPPLY PORTFOLIO AND PGC

Q. Has UGI Gas proposed to adopt a unified gas supply portfolio in this proceeding?

A. Yes, the Company proposes to adopt a unified gas supply portfolio effective November 1, 2019, to avoid the need to make mid-month supply adjustments.

Q. Are there benefits to having a single uniform gas supply plan for UGI Gas?

A. Yes. The current practice of administering three separate gas supply plans across three rate districts no longer makes sense now that the three prior NGDCs have merged and propose to establish establishing uniform base rates in this proceeding. Maintaining three separate supply portfolios based on prior separate corporate identities simply requires UGI Gas to maintain administrative functions and associated costs that identify, track and administer separate supply portfolios and to make three separate PGC filings until the unified supply portfolio is implemented. Maintaining these efforts to keep the portfolios separate simply increases the costs to administer the gas supply function, to the detriment of UGI Gas, the Commission, public parties with an interest in the PGC process, and our gas customers.

Q. Has UGI Gas proposed to adopt a unified system-wide PGC rate in this proceeding?

A. Yes, UGI Gas proposes to establish a unified PGC rate which would be implemented upon the effective date of the rates established in this proceeding. A unified PGC rate should help Choice Suppliers by providing a uniform price to compare across the entirety of UGI Gas's service territory and reduce customer confusion resulting from the existing system of differing PGC rates across what are often geographically proximate rate districts. It should also result in reduced administrative costs with respect to the rate-setting portion of annual PGC filings, and is a necessary and appropriate compliment to the process of establishing uniform base rates.

VII. GAS INFORMATION SYSTEM WEBSITE UPGRADE AND COST

Q. Please describe the Company's GIS website.

A. UGI Gas's GIS website is a portal utilized to communicate with Gas Suppliers who deliver energy to UGI Gas's distribution system for UGI Gas Transportation customers. The website has separate business unit sub-sites and provides and receives data to and from suppliers for several business-critical processes. Gas supply, rates, and billing data and functionality currently available on the website includes:

- Public Content published by the GIS Administrators on request per UGI stakeholder departments – examples of such content are UGI Operating Tariffs, Operational Notices, Operational Flow Orders and Daily Flow Directives, Contact Information, Supplier Delivery Procedures, Request For Proposal Postings, Pricing, Rates, and Heating Degree Day History.
- Web applications supporting key supplier-initiated business processes such as nomination submission, nomination balancing, customer measurements, billing and pool allocations, Choice Supplier DDR and reconciliation.

Supplier-specific content requires entry of user credentials to provide secured access to web applications designed to support supplier business interactions with UGI Gas. The current GIS website originated more than twenty years ago based on a site design using directory-based security on a Linux server and Apache and LDAP for user authentication. Website application maintenance in certain language applications is managed in-house by the UGI Gas personnel.

Q. Why are changes to the GIS website necessary?

A. Changes are required to the GIS system to support new consolidated transportation rules, to provide enhancements based on input from suppliers, and to update to more current technology.

Q. What are the costs associated with the proposed GIS website changes?

A. The Company estimates a third-party development cost of $480,000 plus an additional annual maintenance cost of $52,800.

Q. Does this conclude your direct testimony?

A. Yes.

UGI GAS EXHIBIT AMB-1

(Resume)

Angelina M. Borelli
Director – Gas and Electric Supply

Work Experience

2015 – current	Director – Gas and Electric Supply UGI Utilities, Inc., Reading, PA
2014 – 2015	Director – Gas Supply UGI Energy Services, LLC. Wyomissing, PA
2009 – 2014	Manager – Gas Supply and Transportation UGI Energy Services, LLC. Wyomissing, PA
2006 – 2009	Administrator – Assets & Wholesale Services UGI Energy Services, LLC. Wyomissing, PA
2000 – 2006	Analyst – Gas Supply UGI Utilities, Inc., Reading, PA

Previous Testimony

Default Service Plan:	Docket Nos. P-2016-2543523, G-2016-2543527
Base Rate Case:	Docket-2015-2518438, Docket – R-2016-2580030
2016 PGCs:	Docket Nos. R-2016-2543311 (UGI CPG); R-2016-2543309 (UGI Gas) and R-2016-2543314 (UGI PNG)
2017 PGCs:	Docket Nos. R-2017-2602627 (UGI CPG); R-2017-2602633 (UGI PNG); R-2017- 2017-2602638 (UGI Gas)
2018 PGCs:	Docket Nos. R-2018-3001631 (UGI CPG); R-2018-3001632 (UGI PNG); R-2018- 2018-3001633 (UGI Gas)

Education

M.S Finance from Penn State University, 2008
B.S. in Business Administration from Albright College, 2006
A.A.S in Law Enforcement Administration from RACC, 2000

UGI GAS EXHIBIT AMB-2

(Uniform Nomination and Confirmation Procedures and Communications Protocols)

Supply Nomination Confirmation Procedure		
Nomination Cycle	Nomination Cycle Deadlines (EST)	Supplier Action
Timely	2 p.m.	1. Submit supply nomination(s) on UGI's Energy Management Website ("Website")
Evening	7 p.m.	1. Contact UGI On-Call Scheduler* after supply nomination(s) submitted on pipeline(s) 2. Enter supply nomination package(s) out on Website (UGI Scheduling Team to update volumes) 3. Submit Supply Nomination Change Request Form** to UGI Scheduling Team at GasMgmtGasTraders@ugi.com
ID1/ID2	11 a.m./3:30 p.m.	1. Contact UGI Pipeline Scheduler after supply nomination(s) submitted on pipeline(s) 2. Enter supply nomination package(s) out on Website (UGI Scheduling Team to update volumes) 3. Submit Supply Nomination Change Request Form** to UGI Scheduling Team at GasMgmtGasTraders@ugi.com
ID3	8 p.m.	1. Contact UGI On-Call Scheduler* after supply nomination(s) submitted on pipeline(s) 2. Enter supply nomination package(s) out on Website (UGI Scheduling Team to update volumes) 3. Submit Supply Nomination Change Request Form** to UGI Scheduling Team at GasMgmtGasTraders@ugi.com
*On-Call Schedule		
**Note: If there is a pipeline cut and your supply nomination is unchanged (contract and total volume remain the same), contact the appropriate UGI Pipeline/On-Call Scheduler, but no need to submit a Supply Nomination Change Request Form.		

UGI GAS EXHIBIT AMB-3

(Summary of Collaborative Comments and Suggestions)

UGI Utilities, Inc.
Uniform Choice and Non-Choice Transportation Proposal
Summary of Comments, Suggestions, and Company Responses
1/11/19

General Q&A

Question 1
We did notice that the proposed effective date of these rules is November 1, 2019. During the initial meeting a Proposed date of Fall 2020 was circulated. We believe that November 2020 is the earliest that the transportation changes should be implemented.

Company Response
The Company will propose an effective date of November 1, 2020 for uniform non-choice transportation program changes in the upcoming tariff filing.

Question 2
Do you have an approximate date for when the Choice changes would go into effect?

Company Response
The Company proposes to implement changes to the Choice program upon the establishment of a uniform PGC rate.

Question 3
Do you propose any changes to negotiated service agreements?

Company Response
The Company does not propose any changes to negotiated service agreement terms.

Customer Regions and Delivery Rules

Question 1
In order to adequately judge the impacts of these changes to our customer base, as well as any future customers we add, we will need to be able to determine which region all choice AND non-choice customers fall into. Your current Choice customer list has the current regions listed, so if the non-choice customers were added to this list, as well as the future regions (Southeast, etc. instead of the current Lancaster, etc.), that would be an excellent way to do it. When do you think something like this could be made available for marketers?

Company Response
The Company is currently assessing a method of communicating customer regions for choice transportation customers. Additionally, to be clear on the proposal for Choice customers, the Company proposes a uniform program where customers will receive the same allocation of the Company's supply assets eliminating the current customer regions utilized in the Company's North and Central Rate Districts.

Question 2
Will there be 1 electronic bulletin board for all 4 regions? Will there be separate EBBs for Choice and Non-Choice?

Company Response
To support the new combined transportation rules and pooling, the EBB will be consolidated into two sites for each supplier (UGI Gas Division and UGI Electric Division). Post-consolidation, gas supplier nomination activities for Choice and Non-Choice will continue to occur under a single EBB site (UGI Gas Division).

Question 3
We are concerned with the pipeline delivery rules for the Southwest regions. Columbia Op Area 8 is physically unrelated to the rest of the southwest customer base, and a 15% delivery requirement is cumbersome. It is our position that customers in Columbia Op Area 8 are uniquely situated in a capacity constrained area and should be

treated as their own separate pool. We propose that the Southwest delivery requirements should be 100% for Texas Eastern West of Dauphin.

Company Response
The Company will adopt this recommendation and proposes splitting the Southwest region into two, one requiring deliveries on Columbia in Operating Area 8, the other requiring deliveries on Texas Eastern in Market Area 3.

Question 4
Page 1. With regard to the proposed pipeline splits in Table 1, are these splits intended to be mandatory across the pipelines listed? How are these splits going to be managed in view of the alternative pipelines listed in Table 3?

Company Response
The pipeline splits in Table 1 are intended to be mandatory. NGSs may use an acceptable substitute for a required pipeline delivery. A list of such acceptable substitutes can be found in Table 3.

Question 5
Regarding the Southeast region, we are concerned with the delivery requirements for Columbia Op Area 4. We request that UGI provide total flow capacity on Columbia Op Area 4, as well as for TETCO M3 East of Dauphin.

Company Response
The total flow capacity for Texas Eastern M3 can be found on Texas Eastern's electronic bulletin board at https://link.spectraenergy.com/ by selecting capacity, operationally available, viewable and printable format. The total flow capacity for Columbia Operating Area 4 can be found on Columbia's electronic bulletin board at www.columbiapipelineinfo.com, by selecting capacity and operationally available.

Question 6
Page 1. With regard to Table 1, and the Southwest and Southeast in particular, is it UGI's understanding that TCO will require transit points? That would be a potential negative.

Company Response
The Company has neither requested nor been asked by TCO to establish transit points.

Question 7
Page 2. Table 3, substitute pipelines. We need to understand the rules for nominations in light of these alternatives, which appear to be mostly, if not exclusively, UGI affiliated pipelines, and how those who own capacity on those lines will be permitted to use it, without creating an unfair competitive advantage.

Company Response
The alternate delivery points available under the Company's proposal include supply and production assets, some of which are owned by subsidiaries of UGI Energy Services. UGI Storage Company, UGI Mt. Bethel Pipeline Company, and Sunbury Pipeline Company are FERC regulated interstate pipelines that offer firm and interruptible capacity on a non-discriminatory open access basis, through open seasons, available capacity postings, and capacity release. The pipeline tariffs, information about capacity, and an index of customers for UGI Storage Company, UGI Mt. Bethel Pipeline Company, and Sunbury Pipeline Company can be found at their corresponding websites at www.ugimtbethelpipeline.com, www.sunburypipeline.com, and www.ugistorage.com.

Question 8
Regarding Table 3, we have substantial concerns that all of the alternate delivery options are owned and operated by UGI Energy Services, an affiliate of UGI Utilities, which gives UGI's affiliate a competitive advantage over all other suppliers. Under this proposal, competition in the South East portion of UGI's territory would essentially be eliminated.

Company Response
The alternate delivery points available under the Company's proposal include supply and production assets, some of which are owned by subsidiaries of UGI Energy Services. UGI Storage Company, UGI Mt. Bethel Pipeline

Company, and Sunbury Pipeline Company are FERC regulated interstate pipelines that offer firm and interruptible capacity through Open Seasons, available capacity postings, and via capacity release. Excluding the alternate delivery points prevent transportation customers and NGSs from access to additional natural gas supply options.

Pooling and Balancing

Question 1
How will the current situation of having 3 sets of balancing Pools 1-22 be impacted? What would it look like going forward? Please go into more detail on any changes that will impact this.

Company Response
Under the proposed rules, Suppliers with non-daily read customers in Rates DS and IS, Cycles 1 thru 21 would maintain separate DS/IS pool for each region.

Question 2
Page 3. NNS. We think NNS should be the default so that unless the customer chooses something else, NNS is the norm. Also, we suggest that the minimum daily balancing level is too low and should be 10% across the board. If UGI insists on a lower number, it should be no less than 5%.

Company Response
The Company proposes to consolidate basic balancing service with No-Notice Service resulting in all firm transportation customer service agreements having a default NNS service that provides a firm minimum daily balancing tolerance of 4.5%. The basis of the 4.5% is the consolidation of the current basic balancing service provided in the Company's three Rate Districts. The Company does not hold supply assets which would allow for a 10% tolerance.

Question 3
I believe there is a program in place that will have most if not all transportation customers having daily telemetering? Is this still the plan and when will it be finished? This will make it much easier to balance these smaller customers.

Company Response
UGI has plans to propose an expansion of daily telemetering via a filing with the Pennsylvania PUC no later than January 31, 2019. That filling will outline a proposed timeline and implementation plan.

Question 4
Page 4. We believe that cash-outs should reflect the delivery splits, particularly for the Southeast and Southwest.

Company Response
The Company's proposes using Texas Eastern indices for the cash-out prices in the Southeast and Southwest delivery regions as there is no published index for delivered markets on the Columbia pipeline.

Question 5
Page 6. LMI Cash outs. It appears that the Central and Southwest definitions are reversed. If this arrangement was intended, we need to understand the apparent change.

Company Response
The LMI Cash outs are mislabeled on Page 6 of the proposal. The Central Region and Southwest Regions are reversed.

Question 6
Please confirm whether any of my customers would have been subject to penalty during the winter 2017-18 as a result of the consolidation of daily basic balancing from 10% to 2.5%.

Company Response
The reduction from 10% to 4.5% only impacts customers who don't elect NNS or when NNS is interrupted. Since all of your customers elect NNS, and NNS was not interrupted during the Winter 2017-18, there would not have been a negative impact of those customers if the 4.5% balancing tolerance was in effect.

Question 7
Please confirm the proposed calculation of the cash-in/cash-out indices.

Company Response
The Company proposes region-based indices for daily and monthly imbalances. A list of such imbalance indices is listed below:

Shortfall Monthly Index
Average of the published Gas Daily Midpoint Index Prices for each customer region (listed below) during the Customer's billing month.

North Region
Tennessee, zone 4-300 leg PLUS the applicable transportation costs from Tennessee, zone 4 to zone 4.

Central Region
The higher of 1) Transco, zone 6 non-N.Y. or 2) Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.

Southeast
The higher of 1) Texas Eastern, M-3 or 2) Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3

Southwest
The higher of 1) Texas Eastern, M-3 or 2) Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3

Excess monthly Index
Average of the published Gas Daily Midpoint Index Prices for each customer region (listed below) during the Customer's billing month.

North Region
Tennessee, zone 4-300 leg

Central Region
The lower of 1) Transco, zone 6 non-N.Y. or 2) Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.

Southeast
The lower of 1) Texas Eastern, M-3 or 2) Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3

Southwest
The lower of 1) Texas Eastern, M-3 or 2) Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3

High monthly Index
The highest of the published Gas Daily Absolute index prices for each customer region (listed below) during the Customer's billing month.

North Region
Tennessee, zone 4-300 leg PLUS the applicable transportation costs from Tennessee zone 4 to zone 4.

Central Region
The higher of 1) Transco, zone 6 non-N.Y. or 2) Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.

Southeast
The higher of 1) Texas Eastern, M-3 or 2) Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3

Southwest
The higher of 1) Texas Eastern, M-3 or 2) Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3

Capacity Release Programs

Question 1
Just to be clear, for the DS and participating LFD customers, UGI will release the appropriate amount of capacity (e.g. for the SE region 55-70% TETCO and 30-45% TCO for a total of 100%) at $0 rate to the marketers and full projected demand rate to the customer. This capacity will be released on the pipeline to the marketer who will be free to schedule as marketer sees fit. If this is true, then this is a welcome change from the current methodology.

Company Response
For Rate DS customers, the Company proposes releasing capacity or allocating a portion of the Firm Commodity Supply Alternative to the customer, or if directed by the customer, to the NGS. The cost of capacity is proposed to be recovered directly from the Rate DS customers in the form of a Capacity Charge on their utility invoice.
For Rate LFD customers, the Company proposes releasing capacity or allocating a portion of the Firm Commodity Supply Alternative to the customer, or if directed by the customer, to the NGS. The Company does not propose any change to the current method of recovering capacity costs from participating Rate LFD customers via the capacity release.

Question 2
Will the DS TETCO/TCO ratios vary from month to month or year to year?

Company Response
At this time, the Company will be proposing a fixed ratio of TETCO and TCO capacity release that will not vary from month to month or year to year. However, the Company reserves its right to monitor the operational flexibility of its distribution system and to implement changes to the capacity release program and delivery rules in order to prudently manage system operations.

Question 3
The amount of capacity released is based on the customer Maximum Daily Quantity (MDQ), which I believe is different than what we get today. Will there be a change from the current methodology of calculating the current release? Currently marketers nominate DS capacity for the month 5 days before the end of the month and this number is subject to negotiation between UGI and the marketer. We believe that if the capacity release is based on the MDQ then the amount released wouldn’t change from month to month, assuming no change in the customer base. What is the definition of the contractual MDQ and will it be publicly available?

Company Response
The Company proposes to provide a capacity release or allocation of Firm Commodity Supply Alternative to all Rate DS customers in an amount equal to the customer’s MDQ. The service agreements for Rate DS customers in the Company’s North and Central Rate districts include MDQs. The Company proposes to assign an MDQ to all Rate DS customers in the South Rate District. The MDQ and capacity release quantity will not change from month to month but may change based on request by the customer and approval by the Company. The Company has identified an enhancement to expand the Large Transportation Customer list to include Customer MDQ, DFR, and NNA elections on the Energy Management website. This information will be available to NGSs for their own customers.

Question 4
With the change in DS delivery method will the current early deadline remain? We see no reason for this if the capacity is released directly to marketers.

Company Response
The Company proposes to eliminate the 10:30 am daily nomination deadline for Rate DS UGI capacity nominations and maintain only the current Supply -3rd Party nomination deadline of 2:00 pm for all Supply nominations.

Question 5
Page 2. We do not understand the term "Firm Commodity Supply Alternatives" -- is this the same as Delivered Supply? If not, please explain.

Company Response
Please see Section 7.3 of the Company's tariffs for a definition of Firm Commodity Supply Alternatives. Delivered Supply is a Firm Commodity Supply Alternative.

Question 6
Page 3. LFD & XD. How often will the election under LFD and XD be permitted? Change of supplier, monthly, annually? At a minimum, the customer should be permitted to change when changing suppliers or semi-annually.

Company Response
Subject to the terms of a customer's Service Agreement, Rate LFD customers are permitted to elect UGI capacity at any time and Rate XD customers are permitted to elect UGI capacity at any time subject to availability. However, each election must remain in place for at least 12 months before changing it.

Choice Program

Question 1
II**. Proposed Uniform Non-Choice Transportation Rules** – we assume this section is Choice and not non-Choice.

Company Response
Section II of the Company's proposal addresses Choice transportation rules.

Question 2
To clarify, the monthly release of interstate pipeline capacity will be 45% of the PDDR for each marketer's customer pool. The rate for this capacity will be calculated as follows

a. Aggregated PDDR X 0.45 = release volume. (in SE this will be 30-45% TCO and 55-70% TETCO).
b. 1000 PDDR X .45 = 450 dth of capacity (at 30/70 this will be 135 dth TCO and 315 TETCO)
c. Weighted average demand cost /.45 = Release Rate
d. Or $2/.45 = $4.444/dth

Company Response

a) The Company proposes to eliminate regionally based capacity assignments that are currently utilized in its North and Central rate districts and provide a capacity release or Firm Commodity Supply Alternative on all the pipelines in the Company's supply portfolio to participating Choice customers. As a result, NGSs will receive a release on Texas Eastern, Columbia, and Tennessee. The total quantity of capacity released will be equal to the Aggregated PDDR X 0.45.
b) An NGS with an Aggregated PDDR of 1,000 dth would receive 450 dth/day of firm transportation capacity or allocation of Firm Commodity Supply Alternative.
c) The rate charged to the NGS on the capacity release would be equal to the Company's Weighted Average Cost of Capacity / .45. The .45 or 45% represents the Allocation of Firm Transportation Capacity and Firm Commodity Supply Alternative that will be updated on an annual basis to reflect changes to the Company's supply portfolio.
d) In the case where the Company's Weighted Average Cost of Capacity is equal to $2 / dth /day, the capacity release rate would be equal to $4.444 dth ($2/.45).

Question 3
Please explain the Maximum Daily Quantity calculation of 22%. It looks like you are referring to the bundled portion, as capacity is 45% and peaking is 33%. Please clarify.

Company Response
The Company proposes a uniform choice program where NGSs receive an allocation of FT/Firm Commodity Supply Alternative, Bundled sale, and Peaking in the amount of 45%, 22%, and 33% of their aggregated PDDR respectively. The maximum daily quantity calculation of 22% refers to the bundled sale.

Question 4
In the initial proposal a Uniform Choice program was proposed, with capacity, bundled sale and peaking for all 4 regions at the same percentages. Is this still the goal? So no matter where the customers are located (having no current CPG or PNG Honesdale or North customers) Choice participants would still receive Tennessee capacity and be required to deliver Tennessee gas. Is this true?

Company Response
The Company proposes a uniform choice program where participating customers will not have locational or regional capacity allocations or delivery requirements. Under the Company's proposal, all customers would have the same percentage allocation of capacity, bundled sale, and peaking and would be required to make deliveries on Columbia, Texas Eastern, Transco, and Tennessee.

Question 5
Page 3. Proposed Uniform [Non-] Choice Transportation Rules. Will the asset allocation (FT, Bundled Sale and Peaking) and FT allocation (Columbia, Tetco, Transco and Tennessee) percentages change annually? Or are they set permanently? Refer to pages 30 and 31 in the presentation.

Company Response
The Company will continue its historic practice to review and make changes to the allocation of assets annually in order to ensure that Choice customers receive access to a proportionate share of the PGC's supply portfolio.

Question 6
Page 4. We propose that UGI NOT cap the bundle for UGI South and instead, bill suppliers for what they actually use to make it more like real storage. We also don't understand UGI's rationale for proposing to reduce the limit on the peaking sale.

Company Response
The Company requires additional information to assess the proposal to bill suppliers for what they actually use; providing examples may be helpful to understand the proposal.
The Company's rationale for its proposed uniform Choice program is a consolidation of all assets for the three rate districts resulting in a uniform allocation of transportation, bundled, and peaking supply for all Choice customers. The uniform proposal results in a lower allocation of peaking and a higher allocation of firm transportation capacity for UGI South Rate District customers.

Question 7
Page 4. In the initial proposal an asset allocation included FT/Delivered supply, bundled sale, and peaking for all 4 regions at uniform percentages (Presentation page 30). Is this proposal still on the table? Under such a proposal we would expect that no matter where the customers are located, Choice participants would still receive Tennessee capacity and be required to deliver Tennessee gas. Is that assumption correct?

Company Response
The Company's proposes to allocate assets on a uniform basis to all choice customers and require deliveries on: Columbia, Transco, Tennessee, and Texas Eastern, no matter where the customers are located. The Company proposes to implement changes to the choice program upon establishment of a single consolidated Purchased Gas Cost ("PGC") rate.

Question 8
While not addressed in UGI's proposal, we are concerned with the increasing delivery supplies to the choice program and our limited access to that supply. Specifically, we pay a demand charge for all delivered supply, regardless of whether we take it. We are limited to its actual demand, and if the delivered supply exceeds that limit, we get cashed out. We are unable to transfer length from the choice pools to other pools. We intend to propose some language to address its concerns related to this issue.

Company Response
The Company will review and consider any proposed language changes related to the Choice program.

UGI GAS EXHIBIT AMB-4

(Summary of Existing Customer Regions and Delivery Requirements
for Non-Choice Transportation customers)

Existing Customer Regions and Delivery Requirements			
	Rate District	Nomination Group	Delivery Pipeline Requirement
1	South	Primary	Texas Eastern (55%- 100%) Columbia (0%-45%)
2	South	Secondary	Transco
3	North	Central	Transco
4	North	Northeast	Transco (56%) Tennessee (44%)
5	North	South	Transco
6	North	Honesdale	Tennessee
7	Central	North Penn East	Tennessee
8	Central	North Penn West	Tennessee
9	Central	Northeast	Transco
10	Central	Southeast	Columbia
11	Central	Central	Texas Eastern
12	Central	West	Columbia

UGI GAS EXHIBIT AMB-5

(Summary of Proposed Customer Regions and Delivery Requirements
for Non-Choice Transportation customers)

Proposed Delivery Regions and Requirements	
Region	Delivery Requirement
North	100% Tennessee
Central	100% Transco
Southeast	30%-45% Columbia MA 21, 23, 25, 29 55%-70% Texas Eastern – Meters east of and including Dauphin & York
West	100% Columbia – Market Area 36
Southwest	100% Texas Eastern – meters west of Dauphin & York

UGI GAS EXHIBIT AMB-6

(Proposed Acceptable Substitutes for Delivery Requirements)

Addition Substitute Pipelines	Delivery Pipeline Replacement
Local Production meters, Gathering Systems	Tennessee
UGI Storage Company	Tennessee
UGI Mt. Bethel Pipeline Company	Columbia (Southeast Region)
Sunbury Pipeline Company	Texas Eastern (Southeast region)

UGI GAS EXHIBIT AMB-7

(Summary of Current and Proposed Daily Balancing Tolerances)

Daily Balancing Entitlements Prepared for Collaborative Meeting in September 2018			
	Cumulative Transportation DFR/MDQ (mcf)	Current Daily Balancing Tolerance	Current Daily Balancing Entitlements (mcf)
Rate District	A	B	A x B
Central	67,920	2.5%	1,698
North	572,725	2.5%	14,318
South	211,828	10.0%	21,183
Proposed	852,473	4.4%	37,199

UGI GAS EXHIBIT AMB-8

(Summary of Existing Capacity Release Rules for Rate LFD and Rate DS Transportation Customers Across UGI Gas' Existing Rate Districts, and Its Proposed Standardized Rules)

Rate LFD Customers				
Rate District	South	North	Central	Proposed Uniform
Enrollment	Customer election	Customer election	N/A	Customer election
Quantity	Up to DFR	Up to DFR	N/A	Up to DFR
Rate	WACOD*	WACOD*	N/A	WACOD*
Billing	Capacity Release	Capacity Release	N/A	Capacity Release

Rate DS Customers				
Rate District	South	North	Central	Proposed Uniform
Enrollment	Automatic	Automatic	N/A	Automatic
Quantity	Usage based	MDQ**	N/A	MDQ**
Rate	WACOC***	WACOD*	N/A	WACOD*
Billing	Capacity Release	Capacity Release	N/A	Capacity Release

*Company's weighted average cost of capacity
**Customer's Maximum Daily Quantity
***Company's weighted average cost of capacity as calculated in accordance with PUC Order at Docket No. R-00974012

UGI GAS STATEMENT NO. 13 – THEODORE M. LOVE

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3006814

UGI Utilities Inc. – Gas Division

Statement No. 13

Direct Testimony of
Theodore M. Love
(Green Energy Economics Group, Inc.)

Topics Addressed: **Energy Efficiency & Conservation Plan and Total Resource Cost Implementation**

Dated: January 28, 2019

I. INTRODUCTION

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

A. My name is Theodore M. Love, and I am a partner at Green Energy Economics Group, Inc. ("GEEG"), an energy consulting firm founded in 2005. My office address is 147 South Oxford Street, Brooklyn, New York.

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

A. My testimony is submitted on behalf of UGI Gas Utilities, Inc. – Gas Division ("UGI Gas" or "Company").

Q. Please briefly describe your qualifications.

A. I have been involved in the review and preparation of gas and electric energy efficiency plans, as well as potential studies and cost-effectiveness analysis, in nearly a dozen states, two Canadian Provinces, and China, since I began working with GEEG in 2007. Most relevant to this proceeding, I have been advising UGI Gas on the Energy Efficiency and Conservation ("EE&C") Plan for its South Rate District since 2015, and the EE&C Plan for its North Rate District since 2016. I have also been advising Philadelphia Gas Works ("PGW") on its energy efficiency activities since August 2008 and Peoples Natural Gas Company LLC ("Peoples") since October 2017. My educational background and relevant experience is set forth in my resume attached as UGI Gas Exhibit TML-1 to my testimony.

Q. Have you presented testimony in proceedings before the Pennsylvania Public Utility Commission ("Commission")?

A. Yes. Please see UGI Gas Exhibit TML-1 for a complete listing of the proceedings in which I have testified and their docket numbers.

Q. What is the purpose of your testimony?

A. My testimony will address the Company's proposal for a Consolidated EE&C Plan.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

- UGI Gas Exhibit TML-1 – Resume of Theodore M. Love; and
- UGI Gas Exhibit TML-2 – UGI Gas's Consolidated Five-Year EE&C Plan.

Q. Please summarize your testimony.

A. Section I is an introduction to my testimony. In Section II, I provide a brief overview of the performance of the Company's existing gas EE&C Plans. In Section III, I provide an overview and justification of the Consolidated EE&C Plan. In Section IV, I discuss the benefits, costs, and staging of the Plan's proposed portfolio of programs. In Section V, I provide details on updates to the Consolidated EE&C Plan with respect to the Company's existing gas EE&C Plans. I provide my conclusions and recommendations in Section VI.

II. UGI GAS NORTH AND SOUTH EE&C PLAN OVERVIEW AND PERFORMANCE

Q. How many EE&C Plans does the Company currently manage?

A. The Company manages a voluntary EE&C Plan for its North Rate District and a voluntary EE&C Plan for its South Rate District. The Central Rate District does not currently have an EE&C Plan. The Consolidated Plan proposed by the Company in this proceeding will be available to all eligible customers.

Q. Please describe the UGI South Rate District EE&C Plan.

A. The UGI South Five-Year EE&C Plan ("South EE&C Plan") was approved as part of the former UGI Gas's 2016 Rate Case (Docket No. R-2015-2518438). The South EE&C Plan had projected spending of approximately $24 million over five years on natural gas efficiency programs and approximately $3 million on a Combined Heat and Power ("CHP") Program. The natural gas efficiency programs were projected to save 7,016 Billion British thermal units ("BBtus") of gas over the lifetime of measures installed, and the CHP Program was projected to reduce net energy consumption by an additional 25,591 BBtus over the lifetime of the installed CHP plants. Table 1 provides a summary of the projected Total Resource Cost ("TRC") test results for the South EE&C Plan at the inception of the plan.

Table 1. South EE&C Plan TRC Test Projections

PV 2015$	Benefits	Costs	Net	BCR[1]
Total	$172,528,340	$104,668,959	$67,859,381	1.65
EE Programs	$53,852,243	$30,623,169	$23,229,074	1.76
CHP Program	$118,676,097	$74,045,790	$44,630,307	1.60

[1] BCR stands for benefit-cost ratio.

In its initial filing, the UGI South EE&C Plan included demand reduction induced price effects ("DRIPE"), (the effect on energy prices due to reduced energy usage), and the internalized market cost of carbon dioxide CO_2 (carbon taxes) in the calculation of cost-effectiveness. As approved by the settlement in the UGI Gas rate proceeding, actual results are reported in the Company's annual reports with and without the economic effects of CO_2 (carbon taxes) and DRIPE.

The South EE&C Plan has had a very successful first two years, from October 1, 2016 through September 30, 2018, exceeding its savings and cost-effectiveness goals while maintaining projected spending levels. Tables 2 and 3 summarize the results from the South EE&C Plan Annual Reports.

Table 2. South EE&C Plan Results for PY1 and PY2 - Spending and Savings

Program	Actual	Projected	%
Portfolio Spending	$6,796,112	$6,874,385	99%
EE Programs	$6,784,826	$6,113,386	111%
CHP Program	$11,286	$761,000	1%
EE Program Natural Gas Savings			
Annual (MMBtus)	145,019	69,336	209%
Lifetime (MMBtus)	2,732,181	1,273,331	215%

Table 3. South EE&C Plan Results for PY1 and PY2 - Test Results

PV 2015$	Base Case	w/ DRIPE CO_2
Benefits	$16,885,969	$20,638,787
Costs	$9,902,438	$9,902,438
Net Benefits	$6,983,531	$10,736,349
BCR	1.71	2.08

Q. Please describe the UGI North Rate District Plan.

A. The UGI North Rate District Five-Year EE&C Plan ("North EE&C Plan") was approved as part of the UGI Penn Natural Gas, Inc. ("UGI PNG") 2017 base rate proceeding at

Docket No. R-2016-2580030. The North Plan had projected spending of approximately $14 million over five years on natural gas efficiency programs and approximately $1.4 million on a CHP Program. The natural gas efficiency programs were projected to save 4,160 BBtus of gas over the lifetime of measures installed, and the CHP Program was projected to reduce net energy consumption by an additional 12,739 BBtus over the lifetime of the installed CHP plants. Two versions of the TRC test were utilized for cost-effectiveness projections: a base case and the base case with the addition of DRIPE and CO_2. Table 4 shows the projected TRC Test results for the North EE&C Plan at the inception of the plan.

Table 4. North EE&C Plan TRC Test Projections[2]

PV 2016$	Benefits	Costs	Net	BCR
Base Case	$70,751,757	$55,209,010	$15,542,747	1.28
EE Programs	$23,071,539	$16,195,222	$6,876,317	1.42
CHP Program	$47,680,217	$39,013,788	$8,666,430	1.22
W/ DRIPE and CO_2	$110,011,604	$55,209,018	$54,802,587	1.99
EE Programs	28,029,438	16,195,222	$11,834,216	1.73
CHP Program	81,982,166	39,013,796	$42,968,370	2.10

The North EE&C Plan's first program year ran from October 1, 2017 through September 30, 2018. During this period, the Company was able to deliver cost-effective programs that exceeded savings goals while only spending around half of the projected budget. Tables 5 and 6 provide an overview of the UGI North EE&C Plan results for PY1.

[2] As the North EE&C Plan incorporated the requirement in the South EE&C Plan to break out TRC test *results* with and without the impact of CO_2 and DRIPE, the initial TRC *projections* were filed showing the base case projections as well as projections factoring in the economic effect of CO_2 and DRIPE.

Table 5. UGI North EE&C Plan Results for PY1 – Spending and Savings

Program	Actual	Projected	%
Portfolio Spending	$1,034,332	$1,849,651	56%
EE Programs[3]	$1,028,124	$1,567,151	66%
CHP Program	$6,208	$282,500	2%
EE Program Natural Gas Savings			
Annual (MMBtus)	21,811	15,139	144%
Lifetime (MMBtus)	358,347	276,754	129%

Table 6. UGI North EE&C Plan Results for PY1- Test Results

PV 2016$	Base Case	w/ DRIPE CO_2
Benefits	$1,763,148	$2,174,274
Costs	$1,259,420	$1,259,420
Net Benefits	$503,728	$914,854
BCR	1.40	1.73

III. <u>OVERVIEW OF CONSOLIDATED PLAN</u>

Q. Why is it appropriate for UGI Gas to continue to provide gas EE&C programs to its customers?

A. Improving energy efficiency and addressing climate change in all end uses of energy resources is an increasingly important part of this nation's energy, economic, and environmental policy goals. Over the past decade, numerous nationwide initiatives have focused on improving efficiency. In Pennsylvania, the General Assembly has embraced this view by the passage of Act 129 of 2008 ("Act 129")[4] that required, among other things, the implementation of customer-funded EE&C Plans to promote electric energy conservation and efficiency improvements. Act 129 is currently in Phase III, which

[3] Includes transfer of EE&C funds to LIURP per paragraph 36 of the UGI North Rate Case Settlement.
[4] Act 129 of 2008, P.L. 1592, 66 Pa.C.S §§ 2806.1 and 2806.2.

began on June 1, 2016, and it is anticipated to continue to Phase IV in 2021. This reaffirmation of support for Act 129 confirms the value that utility-facilitated energy efficiency programs provide to the residents of Pennsylvania.

In recent years, the Commission has recognized that similar benefits can be realized by Pennsylvania natural gas distribution companies ("NGDCs") implementing EE&C Plans. PGW has been successfully operating a voluntary portfolio of natural gas energy efficiency programs for nearly eight years, the second phase of which was approved in October of 2016 at Docket No. P-2014-2459362. PGW's programs have resulted in over 260 BBtus in incremental annual gas savings and a present value of TRC net benefits of $5.7 million from inception through August 31, 2014. PECO Energy Company also offers customers rebates for energy efficient furnaces and boilers through its Smart Ideas Program.[5] Notably, when the Commission approved the South EE&C Plan as part of UGI Gas's 2016 base rate proceeding, both the Company and the parties to the proceeding were commended for having developed a voluntary gas EE&C Plan in the joint statement of Chairman Gladys M. Brown and Commissioner David W. Sweet dated September 1, 2016. UGI Utilities, Inc. – Electric Division has also operated a voluntary Electric Plan since 2012.

Q. Will the Consolidated EE&C Plan, if implemented, benefit UGI Gas customers?

A. Yes, it will. The Consolidated EE&C Plan is based on the already approved EE&C Plans for the South and North Rate Districts. The Consolidated EE&C Plan will allow UGI Gas customers to receive consistent support and messaging regarding energy efficiency

[5] https://www.peco.com/WaysToSave/ForYourHome/Pages/GasOverview.aspx

opportunities and to benefit from reduced energy bills and increased comfort levels while capitalizing on the efficiencies realized by larger scale offerings covering UGI Gas's entire service territory. Section 1.3 of the Consolidated EE&C Plan (UGI Gas Exhibit TML-2) describes the Company's core goals for the EE&C Plan as the following:

- Help customers save energy cost effectively through a holistic approach to energy efficiency and conservation;
- Avoid lost opportunities and provide deep levels of savings;
- Provide a wide range of services for the Company's diverse customer base; and
- Contribute to the economic welfare of its customers and the Commonwealth of Pennsylvania.

UGI Gas is proposing to spend $60.4 million towards natural gas energy efficiency programs, an investment that will return a present value of net total resource benefits of $60.0 million and save customers 24,745 BBtus of gas over the lifetime of measures installed. For the CHP Program, an investment of $3.4 million is projected to return present value net total resource benefits of $21.7 million. Furthermore, although greenhouse gas emissions are not factored into the base TRC net benefits, another added benefit of the proposed Consolidated EE&C Plan is the anticipated avoidance of approximately 4.2 million tons of carbon dioxide emissions over the lifetime of measures installed, which is equivalent to permanently removing around 69,700 cars from the road.

Q. Please summarize the Company's Consolidated EE&C Plan proposed in this proceeding.

A. Over the next five years, UGI Gas proposes to invest $63.87 million in five energy efficiency ("EE") programs and a CHP program. If implemented, the full EE&C

portfolio is expected to provide $81.7 million in net total resource benefits with an overall TRC BCR of 1.49.

The EE programs are expected to cost $60.43 million over five years and reduce natural gas consumption by 24,745 BBtus over the lifetime of the installed measures. The EE programs are estimated to provide the Company's customers with present value of total resource benefits of $135.1 million at a cost of $75.1 million, including participant investments, for a net benefit to customers of $60.0 million with a TRC BCR of 1.80. The EE programs are also projected to save around 1.5 million tons of CO_2 over the lifetime of measures installed, which is the equivalent of removing over 25,000 cars from the road. The proposed CHP Program is projected to cost $3.4 million over the five-year period, to produce a 26,336 BBtu reduction in net primary energy usage over the lifetime of the installed CHP units, and to avoid the emission of approximately 2.6 million tons of carbon dioxide, which is equivalent to removing over 44,000 cars from the road. The CHP Program is estimated to provide $21.7 million in net total resource benefits with a BCR of 1.24. The following table provides a comparison of the spending and savings projected for the Consolidated EE&C Plan compared to the projections for the existing South and North EE&C Plans.

Table 7. Comparison of Consolidated EE&C Plan to Existing EE&C Plans

	Combined South and North EE&C Plans	Consolidated EE&C Plan	Difference
Projected Spending	**$42,432,550**	**$63,870,800**	**51%**
EE Programs	$38,224,950	$60,428,300	58%
CHP Program	$4,207,600	$3,442,500	-18%
EE Programs - Projected Lifetime Gas Savings (MMBtus)	**11,103,295**	**24,745,455**	**123%**
CHP Program - Projected Lifetime Net Energy Savings (MMBtus)	**38,330,491**	**26,336,203**	**-31%**

Q. How was the Consolidated EE&C Plan developed?

A. As described in Section 1.4 of UGI Gas Exhibit TML-2, the Plan was developed utilizing the goals discussed earlier in my testimony. With these principles in mind, measure characterizations and avoided costs were reexamined and updated if necessary, and measures were then screened for cost effectiveness. The cost-effective measures and projects were then used to calculate achievable savings and participation levels based on experience with programs in the North and South Rate District Plans. Program and portfolio projections were adjusted to allow for program ramp-up, and budget constraints to develop a final portfolio.

Q. What are the programs proposed for inclusion in the Consolidated EE&C Plan?

A. The following five natural gas EE programs are proposed for the five-year Consolidated EE&C Plan:

1. Residential Prescriptive (RP)
2. Residential New Construction (RNC)

3. Residential Retrofit (RR)
4. Nonresidential Prescriptive (NP)
5. Nonresidential Custom (NC)

The Plan also includes a CHP Program, which is proposed as a separate fuel-switching program, and a budget for portfolio-wide administrative costs. These six programs will be explained in more detail later in my testimony.

Q. Has UGI Gas provided detailed plans for the proposed programs?

A. Yes, Section 2 of UGI Gas Exhibit TML-2 provides a detailed plan for each of the programs, including annual budgets, savings, and participation projections along with more information on program design, eligible rate classes, target markets, incentive approach, marketing, evaluation, measurement, and verification ("EM&V"), and implementation.

Q. How are low-income customers addressed by the Consolidated EE&C Plan?

A. Low-income customers are addressed in several ways. First, the proposed Consolidated EE&C Plan includes a carve-out of $100,000 annually to be allocated to UGI Gas's Low-Income Usage Reduction Program ("LIURP"). Next, the Company is proposing to waive the customer fee for receiving an assessment under the RR Program for low-income customers who meet income requirements, but do not meet usage requirements for participation in LIURP. Finally, as with the North and South Rate District Plans, UGI Gas will continue to refer potentially eligible customers to its LIURP and will include LIURP messaging on applications and marketing materials, including a direct phone number to contact UGI Gas to pursue enrollment if the customer believes that he or she may qualify.

Q. How does this Consolidated EE&C Plan differ from the North and South EE&C Plans?

A. The Consolidated EE&C Plan is based largely on the Commission-approved North and South EE&C Plans. Program, project, and measure assumptions were recalibrated to include the entire UGI Gas service territory as well as Rate Schedule DS and LFD customers, and to account for current program activity. This process included scaling program participation to align with results from existing programs, updating project and measure assumptions to account for new information, and updating avoided costs to apply to UGI Gas as a combined service territory. Table 1 of UGI Gas Exhibit TML-2 provides an overview of how these programs compare to the existing portfolio of programs offered by the two existing gas EE&C Plans. The primary differences are that the Company does not intend to launch a Behavior and Education ("BE") program, and the Nonresidential New Construction ("NNC") and Nonresidential Retrofit ("NR") Programs have been merged into the Nonresidential Custom Program. Further details on program updates and improvements are provided in Section V of this testimony.

Q. Why does the Company believe that expanding its gas EE&C programs to customers in the UGI Central Rate District will be beneficial?

A. The Company believes that expansion to the UGI Central Rate District will enhance customer satisfaction and reduce confusion regarding customer eligibility. Currently, only customers in the North and South Rate Districts are able to participate in gas EE&C programs offered by the Company. The Company has informed me that many customers in the Central Rate District have inquired about the Company's EE&C programs and were disappointed when they were not eligible to participate. This is understandable given the average customer may not understand the distinctions between the separate rate districts. Therefore, expanding the gas EE&C programs to UGI Central Rate District customers will enhance customer satisfaction and reduce customer confusion. Moreover, by expanding the total number of potential participants, the Company is able to increase the potential cost-effective savings that can be achieved.

Q. Why does the Company believe that expanding its gas EE&C programs to nonresidential Rate Schedules DS and LFD customers will be beneficial?

A. Customers that are served under Rate Schedules DS and LFD are currently only eligible to participate in one EE&C program: The Combined Heat & Power (CHP) Program. The Company has informed me that at least 25 nonresidential customers have inquired about the availability of nonresidential EE&C programs and were disappointed when told they were not eligible to participate because they are either DS or LFD customers. The types of projects these customers inquired about were commercial boilers, water heaters, steam traps, and commercial kitchen equipment, all of which can produce significant energy savings. However, these measures currently are only available to customers served under Rate Schedules N/NT.

Q. Does the Consolidated EE&C Plan address the settlement terms agreed to in the Company's prior settlement agreements in the UGI Gas 2016 and UGI PNG 2017 base rate cases?

A. To the extent those settlement terms remain applicable, yes. Section 1.4.1 of UGI Exhibit TML-2 provides a list of the terms to which the proposed Consolidated EE&C Plan adheres. Settlement terms related to the separation of residential and nonresidential new construction programs, along with specific budget and cost-effectiveness cap figures, were not addressed, as they are no longer relevant given updated program projections and design.

IV. <u>BENEFITS, COSTS, AND STAGING OF THE CONSOLIDATED EE&C PLAN</u>

Q. How did you assess the benefits and costs of UGI Gas's proposed portfolio?

A. Costs and benefits were compared from two perspectives: a total resource perspective and the gas system administrator perspective. The primary test for the Consolidated EE&C Plan is the TRC test, which is the same as that used for the existing North and South EE&C Plans, and is comparable to the test used by PGW for its Phase II plan and is similar to the test used by the Commission for Act 129. This test compares the avoided cost of resources, including natural gas, electricity, and water, against the incremental cost of pursuing efficiency measures and any administration costs incurred under the programs.

Q. What avoided cost values were used in the development of the Consolidated EE&C Plan?

A. UGI Gas Exhibit TML-2 provides an overview of the avoided cost methodology in Section 1.8.2 and tables of projected values in Section 3.1, and I discuss updates to avoided costs in Section V-H of this testimony.

Q. How does the assessment of the CHP Program differ from that of the EE programs?

A. The CHP Program will be evaluated using the same TRC cost-effectiveness criteria as the EE programs. However, as discussed in the testimony of Shaun M. Hart (UGI Gas Statement No. 9) individual CHP projects also will need to demonstrate that they will result in overall net primary energy reduction and meet the economic test established by the final Commission Order entered September 1, 2016, approving the UGI Gas 2016 base rate case settlement. These reductions will be tracked separately because the CHP Program will result in an increase in gas usage that should not be conflated with the savings from the EE programs.

Q. What are the lifetime costs and benefits you estimate from implementing the Consolidated EE&C Plan?

A. The table below (Table 14 from UGI Gas Exhibit TML-2) shows the cost-effectiveness summary for the programs in the Consolidated EE&C Plan. The EE programs are projected to provide UGI Gas customers with present value of total resource benefits of approximately $135.1 million at an estimated cost of $75.1 million, including the participant investments, for a net benefit to customers of approximately $60.0 million with a BCR of 1.80. The CHP Program is estimated to provide approximately $21.7 million in net total resource benefits with a BCR of 1.24. The entire Consolidated EE&C Plan is projected to provide approximately $81.7 million in net total resource benefits with a TRC BCR of 1.49.

Table 8. TRC Cost-effectiveness Summary of EE&C Portfolio

Program	Total Resource PV Benefits	Total Resource PV Costs	Total Resource PV Net Benefits	Total Resource BCR
Residential Prescriptive (RP)	$66,906,943	$36,799,435	$30,107,508	1.82
Residential New Construction (RNC)	$7,986,156	$3,786,306	$4,199,851	2.11
Residential Retrofit (RR)	$11,876,481	$10,010,434	$1,866,047	1.19
Nonresidential Prescriptive (NP)	$30,824,692	$8,147,406	$22,677,285	3.78
Nonresidential Custom (NC)	$16,816,997	$12,415,806	$4,401,191	1.35
Portfolio-wide Costs	$0	$3,511,529	($3,511,529)	0.00
LIURP Transfer	$656,663	$382,906	$273,756	1.71
EE Total	**$135,067,931**	**$75,053,822**	**$60,014,109**	**1.80**
CHP Program	$113,713,664	$91,998,234	$21,715,430	1.24
EE&C Total	**$248,781,595**	**$167,052,056**	**$81,729,539**	**1.49**

If the values for DRIPE and CO_2 are included, then benefits go up significantly, especially for the CHP portion of the portfolio, as shown in the table below (Table 15 from UGI Gas Exhibit TML-2). The EE programs have TRC net benefits of approximately $97.4 million, and the CHP Program has TRC net benefits of approximately $117.3 million, equaling a total of approximately $214.6 million in TRC net benefits with a BCR of 2.28.

Table 9. TRC Cost-effectiveness Summary of EE&C Portfolio (2018) w/ DRIPE & CO_2

Program	Total Resource PV Benefits	Total Resource PV Costs	Total Resource PV Net Benefits	Total Resource BCR
Residential Prescriptive (RP)	$86,025,637	$36,799,435	$49,226,202	2.34
Residential New Construction (RNC)	$9,477,571	$3,786,306	$5,691,266	2.50
Residential Retrofit (RR)	$14,911,896	$10,010,434	$4,901,462	1.49
Nonresidential Prescriptive (NP)	$39,700,986	$8,147,406	$31,553,580	4.87
Nonresidential Custom (NC)	$21,457,045	$12,415,806	$9,041,239	1.73
Portfolio-wide Costs	$0	$3,511,529	($3,511,529)	0.00
LIURP Transfer	$835,609	$382,906	$452,703	2.18
EE Total	**$172,408,745**	**$75,053,822**	**$97,354,923**	**2.30**
CHP Program	$209,284,714	$91,998,234	$117,286,481	2.27
EE&C Total	**$381,693,459**	**$167,052,056**	**$214,641,404**	**2.28**

Q. Will these net benefits stimulate economic activity?

A. Yes. The present worth of TRC net benefits represents a long-term injection of wealth into the economy. For residential customers, the reduction in the total costs of gas service translates to after-tax disposable income, which can be saved or spent. Likewise, lower gas bills for business customers means some combination of increased profit margins and more competitive product and service pricing. Businesses will re-invest the resulting extra profits, distribute them to owners, or some combination of the two. Either way, the TRC savings will stimulate additional business activity.

Moreover, the amount of additional economic activity stimulated by the efficiency investment will end up being several times the net benefits due to re-spending within the local, state, and regional economies. While some spending would be expected to take place outside of Pennsylvania, the majority of the economic benefits stay at the state and local levels.

This economic activity generated by the net economic benefits of efficiency investment is in addition to the economic activity generated directly by expenditures on the part of both the Company and program participants to install the efficiency measures.

Q. How much natural gas will UGI Gas's customers who participate in the EE programs save due to the EE programs?

A. The natural gas efficiency programs are projected to save participating UGI Gas customers 24,745 BBtus over the lifetime of all measures installed. The table below (Table 9 from UGI Gas Exhibit TML-2) shows the first year and lifetime gas savings associated with each sector over the five years of the proposed portfolio of natural gas efficiency programs.

Table 10. Projected Gas Savings (MMBtus)

Sector	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20- '24
First Year Gas Savings	**204,704**	**233,603**	**261,254**	**275,848**	**277,011**	**1,252,420**
Residential	145,463	157,325	171,179	175,233	176,395	825,596
Nonresidential	59,241	76,278	90,075	100,615	100,615	426,824
Lifetime Gas Savings	**4,057,020**	**4,610,820**	**5,158,029**	**5,448,167**	**5,471,418**	**24,745,455**
Residential	2,791,392	2,996,538	3,263,511	3,342,844	3,366,094	15,760,378
Nonresidential	1,265,629	1,614,282	1,894,518	2,105,324	2,105,324	8,985,076

Q. What additional benefits do you project for UGI Gas customers from the EE portion of the Consolidated EE&C Plan?

A. I estimate the proposed EE programs will produce lifetime savings of 77,717 MWh of electricity and 353 million gallons of water and will avoid the emission of approximately 1.54 million tons of CO_2, which is the equivalent of removing over 25,000 cars from the road permanently. Section 1.6 of UGI Gas Exhibit TML-2 contains a more detailed breakdown of additional savings due to the proposed portfolio.

Q. What benefits do you project for UGI Gas customers from the CHP Program?

A. I estimate the CHP Program will reduce net primary energy consumed by 26,336 BBtus over the lifetime of the installed plants.

Q. How much additional employment do you estimate that the Consolidated EE&C Plan will generate?

A. The Plan is projected to generate between 742 and 1,485 net additional new jobs over the lifetime of the efficiency measures installed. The majority of these jobs will stay close to where savings occurred due to: (1) most of the job creation being a product of the economic "multiplier" effect through the cycle of re-spending energy savings; and (2) the shift away from spending in the less-labor intensive energy sector towards more job-intensive sectors such as food service and production, as explained in Section 1.6.6 of UGI Gas Exhibit TML-2.

Q. How much will it cost to achieve these results?

A. The entire Consolidated EE&C Plan is expected to cost $63.87 million over five years (an average of approximately $12.8 million per year). For the natural gas EE programs, UGI Gas projects an investment of $60.43 million, or approximately $12.1 million per year. For the CHP Program, UGI Gas projects an investment of approximately $3.4

million, specifically $688,500 per year. The table below shows the projected annual nominal dollar investment by program.

Table 11. Projected Spending for Consolidated EE&C Plan by Program

Sector	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY ’20- ‘24
Residential Prescriptive (RP)	$5,030,900	$5,833,900	$6,364,100	$6,574,900	$6,494,900	$30,298,700
Residential New Construction (RNC)	837,800	584,200	523,400	644,400	641,500	3,231,300
Residential Retrofit (RR)	1,521,000	2,068,000	2,165,000	2,105,000	2,105,000	9,964,000
Nonresidential Prescriptive (NP)	848,350	1,008,450	995,700	1,055,700	995,700	4,903,900
Nonresidential Custom (NC)	601,000	1,063,800	1,460,000	1,932,800	1,872,800	6,930,400
Portfolio-wide Costs	875,000	900,000	925,000	950,000	950,000	4,600,000
LIURP Transfer	100,000	100,000	100,000	100,000	100,000	500,000
EE Total	**$9,814,050**	**$11,558,350**	**$12,533,200**	**$13,362,800**	**$13,159,900**	**$60,428,300**
CHP Program	635,000	635,000	635,000	635,000	902,500	3,442,500
EE&C Total	**$10,449,050**	**$12,193,350**	**$13,168,200**	**$13,997,800**	**$14,062,400**	**$63,870,800**

The table below reflects projected nominal budgets for the entire portfolio, including CHP, for FY 2020, both by program category and broken out between rate classes.

Table 12. Spending by Rate Class and Category FY 2020

Program Category	R/RT	N/NT	DS	LFD	Total
Customer Incentives	$5,717,700	$527,175	$619,023	$408,153	$7,272,050
Administration	$2,075,770	$213,115	$179,180	$93,934	$2,562,000
Marketing	$258,000	$43,500	$50,450	$33,050	$385,000
Inspections	$137,000	$9,000	$8,800	$5,200	$160,000
Evaluation	$40,000	$0	$15,000	$15,000	$70,000
Total Expenses	**$8,228,470**	**$792,790**	**$872,453**	**$555,337**	**$10,449,050**

Please see Section 1.9 of UGI Gas Exhibit TML-2 for additional details regarding the proposed program staging, as well as Section 2 for individual program descriptions. Please see the direct testimony of David E. Lahoff (UGI Gas St. No. 8) for the EE&C rider calculation for each eligible rate class.

Q. Will UGI Gas be able to offer all the proposed programs starting in FY 2020?

A. Yes. All the programs proposed for the Consolidated Plan are based on programs that are already available to customers. If the Consolidated Plan is approved, UGI Gas will be able to continue offering services to existing customers without interruption and will be able to expand the eligible customer base upon the effective date of new rates.

Q. Is UGI Gas proposing annual budget caps for the individual programs?

A. No. The proposal is an investment over five years of approximately $12.8 million dollars per year. Although the previously described budget levels represent anticipated funding levels, the utility should be allowed to move budget dollars between years and programs depending on market conditions and adoption rates, as long as program and portfolio cost-effectiveness are achieved while not exceeding the five-year total budget cap.

Q. Why is this flexibility important?

A. The ability to allocate funding effectively is crucial for a portfolio administrator. The ability to adjust budgets ensures that unspent funds from one program can be used to address higher demand in other programs and helps provide continuity for customers, contractors, and suppliers. This flexibility must also extend to program design and implementation, such as increasing or decreasing incentives based on market conditions. Notwithstanding, as explained in Section 1.9.5 of UGI Gas Exhibit TML-2, UGI Gas would file a revised EE&C Plan if a program was added or removed, additional funds over and beyond the five-year cap were required, or material changes were expected for portfolio-level cost-effectiveness projections.

Q. How will UGI Gas report results?

A. As described in Section 1.9.4 of UGI Gas Exhibit TML-2, UGI Gas will provide an annual report every January, three months after the close of the program year, that will provide verified savings and participation, costs committed to this activity, and the resulting cost-effectiveness. Results for the previous year and progress towards the five-year goal will be included. The annual report will also include highlights of program activity and any significant improvements made to program delivery and design. UGI Gas will also provide a copy of its annual EE&C Plan report to stakeholders at the time it is submitted to the Commission and will review the report at a stakeholder meeting within three months after the report is submitted to the Commission.

Q. Please describe UGI Gas's EM&V plans for the portfolio.

A. UGI Gas Exhibit TML-2 provides an overview of the EM&V planned for the EE&C Plan (UGI Gas Exhibit TML-2, Section 1.9.9) as well as plans for each individual program. Measures will require proof of purchase and must be tied to a valid UGI Gas account. Third-party inspections will be performed on complex projects and a subset of prescriptive rebates, to make sure the correct equipment is installed and to solicit customer feedback. Savings will be calculated using the technical reference manual ("TRM") that was developed for UGI Gas and is currently used for the North and South EE&C Plans. Further, UGI Gas will utilize a tracking system to store and analyze program activity, spending, and inspection data. Finally, each program will undergo regular impact and process evaluations approximately every two years.

V. DESCRIPTION OF PROGRAMS AND UPDATES IN CONSOLIDATED EE&C PLAN

A. RESIDENTIAL PRESCRIPTIVE PROGRAM

Q. Please describe the Residential Prescriptive Program.

A. The Residential Prescriptive ("RP") Program offers cash incentives for high-efficiency, natural gas powered, residential-sized space and water heating equipment, which is the largest lost opportunity market in UGI Gas's territory. The program is expected to cost $30.3 million in nominal dollars over five years and save 12,532 BBtus of natural gas over the lifetime of measures installed. The program is projected to provide present value TRC net benefits of $30.1 million with a BCR of 1.82. The program will also save approximately 737 thousand tons of CO_2 over the lifetime of the installed measures, which is equivalent to permanently removing over 12,300 cars from the road.

The RP Program specifically provides rebates for high efficiency furnaces, boilers, combi-boilers, tankless water heaters and Wi-Fi-enabled smart thermostats. ENERGY STAR® criteria will be used as the minimum efficiency level, when available. A list of the proposed measures and corresponding incentives can be found in the RP Program Description Section on Financial Incentives in UGI Gas Exhibit TML-2.

Q. How has the RP Program been updated in the Consolidated EE&C Plan?

A. The primary update to the RP was to increase participation and budget projections. The current gas RP programs have experienced strong customer participation since their inception. UGI Gas is increasing savings and participation projections based on this success, along with the inclusion of customers in the current UGI Central Rate District. Proposed incentives for boilers and combi-boilers are being slightly lowered, and inspection rates have been lowered to account for the higher participation projections, lack of issues identified with current efforts, and to save money on inspection costs.

B. RESIDENTIAL NEW CONSTRUCTION PROGRAM

Q. Please describe the Residential New Construction Program.

A. The Residential New Construction ("RNC") Program aims to address natural gas efficiency in residential new construction projects. The program provides incentives for implementing building practices that lead to energy savings above a code-built home. The program is performance-based and will provide participants with a greater incentive for combining measures and implementing deeper saving measures than those offered by upgrading only the space or water heating system through the RP Program. Builders will receive a rebate for achieving savings over code, as measured by a Home Energy Rating System ("HERS") Index score. This program is designed to complement existing new construction programs offered by the Act 129 electric distribution companies ("EDCs"), whose service territories overlap that of UGI Gas.

The program is expected to cost $3.2 million in nominal dollars over five years and save 1,244 BBtus of natural gas over the lifetime of measures installed. The program is projected to provide present value TRC net benefits of $4.2 million with a BCR of 2.11. The program will also save approximately 125,000 tons of CO_2 over the lifetime of the installed measures, which is equivalent to permanently removing over 2,000 cars from the road.

Q. How has the RNC Program been updated in the Consolidated EE&C Plan?

A. The RNC Program has been updated to account for two market trends. First, program projections and savings have been updated to account for the significant over-performance experienced in the first two years of the program's existence. Aligning program design with the Act 129 EDCs has allowed the program to grow very quickly, and the Consolidated EE&C Plan has updated projections to account for this growth.

The other market change is the adoption of new building codes in Pennsylvania. On May 1, 2018, the Pennsylvania Uniform Construction Code Review and Advisory Council ("UCC RAC") announced the adoption of the 2015 International Code Council Code ("2015 ICC"), to go into effect on October 1, 2018.[6] This represents a significant increase in required building practices over the existing code, which is based on 2009 ICC. Of particular importance to the RNC Program, this includes the adoption of the 2015 International Energy Conservation Code ("IECC 2015"), which guides the energy usage characteristics of newly constructed residential buildings in Pennsylvania. To address this change in building codes, the savings, costs, and participation projections for the RNC Program were reexamined and updated.

Q. Will UGI Gas use IECC 2015 as the baseline code for the RNC Program in the Consolidated EE&C Plan?

A. Not necessarily. There is still significant uncertainty regarding the period for which homes will be "grandfathered" under the existing IECC 2009 code. My understanding is

[6] https://www.dli.pa.gov/ucc/Documents/rac/UCC-RAC-2015-Code-Review-Report.pdf

that Pennsylvania Act 36 of 2017 ("Act 36")[7] provides a grace period of six months after the effective date of regulation under which builders may seek permits under IECC 2009. Furthermore, Act 36 allows permits to remain effective for up to two years past the effective date of regulation. Given this, my understanding is that a builder could begin construction on a home permitted under IECC 2009 as late as October 1, 2020, with construction finishing well beyond that date. This makes it very difficult to estimate what the appropriate baseline is for new homes during the lifetime of the proposed RNC Program. The Company will monitor market conditions and may adopt any future guidance provided by the Commission concerning residential new construction baselines under Act 129.

Q. How has the RNC Program been updated to account for the change in code baseline?

A. While uncertainty still exists regarding when builders will switch to the new code, it is clear that by the end of the proposed Consolidated EE&C Plan term there will be a shift towards IECC 2015. The program plan was updated to more flexibly address changing market conditions. UGI Gas plans to gradually shift towards the new code, while working to maintain absolute incentive amounts per project to keep builders engaged in the program. Please see the RNC Program Description in UGI Gas Exhibit TML-2 for a table outlining the proposed incentive and baseline shifts. The Company expects to eventually promote projects that have 15% savings over 2015 IECC, which represents similar levels of building performance that would be achieved by getting 30% savings

[7] ttp://www.legis.state.pa.us/cfdocs/legis/li/uconsCheck.cfm?yr=2017&sessInd=0&act=36

above 2009 IECC. UGI Gas may need to update savings thresholds and incentive levels based on changes in the market or to align more closely with guidance under Act 129.

C. RESIDENTIAL RETROFIT PROGRAM

Q. Please describe the Residential Retrofit Program.

A. The Residential Retrofit ("RR") Program is designed to overcome market barriers for existing residential customers to undertake comprehensive natural gas efficiency projects that save money and increase comfort. The program specifically addresses space and water heating systems, as well as improvements to the thermal envelope in existing residential buildings. The program is expected to cost $10.0 million in nominal dollars over five years and save 1,984 BBtus of natural gas over the lifetime of measures installed. The program is projected to provide present value TRC net benefits of $1.9 million with a BCR of 1.19. The program will also save approximately 120 thousand tons of CO_2 over the lifetime of the installed measures, which is equivalent to permanently removing over 2,000 cars from the road.

Q. How has the RR Program been updated in the Consolidated EE&C Plan?

A. The primary update to the RR Program is the shift of the program from an audit with a blower door test and no direct install measures, to a home energy assessment without a blower door test and with direct install measures. These direct install measures will be an ENERGY STAR® smart thermostat and other low-cost energy saving and health and safety measures. A list of the specific measures included in the assessment is provided in the program description in Section 2 of Exhibit UGI Gas TML-2. The assessment will cost the customer up to $100, whereas the previous audit cost was $150, and will include a full review of the customer's savings opportunities and end with a proposal for additional energy savings. If the customer wishes to do a more comprehensive project, a blower door test will be required as part of the test-in and test-out procedures for the comprehensive project. By not including a blower door test at the initial assessment, this is expected to now take a contractor approximately one hour to do an assessment compared to three to six hours for the full audit. Therefore, the time and cost involved for the contractor are greatly reduced, which in turn reduces the inconvenience and cost for the customer and increases program cost effectiveness.

The inclusion of direct install measures, and in particular the installation of an ENERGY STAR® smart thermostat, as part of the assessment provides a significant value proposition for customers. Therefore, UGI Gas anticipates that the direct install measures will drive a large amount of additional interest in the program. In its most recent program year, the South Rate District facilitated a limited time offer promotion for its existing RR Program that included the installation of an ENERGY STAR® smart thermostat with the completion of an audit and saw participation rates increase significantly. Over 130 audits were completed in only 3 months during the limited time offer, compared to just 86 completed audits in the seven previous months. The direct install measures also allow the program to achieve savings from assessments that do not convert to comprehensive jobs.

All assessments and comprehensive jobs will continue to be performed by qualified contractors in UGI Gas's contractor network.

Q. What does it mean to be a "qualified contractor"?

A. The cornerstone of the RR Program will be the approved contractor network. The contractor network has already been established for the South Rate District and will be expanded throughout larger portions of the Company's service territory.

To become part of the network, a contractor must have a minimum of Building Analyst Certification from the Building Performance Institute ("BPI") and be trained in program protocols to ensure quality business practices. Approved contractors must also employ BPI certified site technicians and site supervisors. Once a contractor passes initial approval, the first three projects performed by that contractor will require confirmation of quality installation by an approved third-party inspector before the contractor moves from probationary status to full certification. Subsequent contractor work will be inspected on up to 5% of assessments and 10% of comprehensive projects.

Q. How have projections for comprehensive projects changed in the updated RR Program?

A. The current incentive design is still proposed for comprehensive projects. The Company anticipates a decline in conversion rates for assessments becoming comprehensive projects under the updated program design. However, the significant growth in the number of projected assessments will more than make up for the decline in conversion rates, and the number of comprehensive jobs projected for the program is expected to increase significantly.

D. NONRESIDENTIAL PRESCRIPTIVE PROGRAM

Q. Please describe the Nonresidential Prescriptive Program.

A. The Nonresidential Prescriptive ("NP") Program offers incentives for a variety of natural gas-powered equipment used by UGI Gas's small business, commercial, and industrial customers. The program is expected to cost $4.9 million in nominal dollars over five years and save 5,945 BBtus of natural gas over the lifetime of the measures installed. The program is projected to provide present value TRC net benefits of $22.7 million with a BCR of 3.78. The program will also save approximately 351,000 tons of CO_2 over the lifetime of the installed measures, which is equivalent to permanently removing over 5,800 cars from the road.

The program provides rebates for commercial-sized boilers, unit heaters, steam traps, water heaters, and a few types of commercial kitchen equipment. Where possible, ENERGY STAR® will be used as the minimum efficiency level. A list of the proposed measures and corresponding incentives can be found in the NP Program Description Section on Financial Incentives in UGI Gas Exhibit TML-2. The NP Program will utilize the same rebate processing vendor as the RP Program to maintain operational efficiency.

Q. How has the NP Program been updated in the Consolidated Plan?

A. There are a few changes to the NP Program. First, the custom incentive track was moved to the Nonresidential Custom Program for operational efficiency. Second, UGI Gas will work closely with suppliers to offer a midstream rebate, firstly for kitchen equipment and secondly for heating equipment. UGI Gas has found more success working with equipment distributors to reduce the cost of the equipment at the time of purchase, and the Consolidated EE&C Plan includes an expansion of these efforts. Third, the list of eligible kitchen equipment and associated rebates was updated to reflect additional market data gathered by UGI Gas. This included removing rebates for steam cookers and pre-rinse spray valves due to existing market saturation and baseline shifts, adding rebates for gas powered griddles and commercial dishwashers, and lowering fryer rebates. Finally, program eligibility was extended to include customers served under Rate Schedules DS and LFD. Overall participation and projections were updated to account for this, as well as the addition of customers in the current UGI Central Rate District.

E. NONRESIDENTIAL CUSTOM PROGRAM

Q. Please describe the Nonresidential Custom Program.

A. The Nonresidential Custom ("NC") Program will provide incentives for overcoming market barriers for natural gas efficiency retrofits in new and existing commercial and multi-family buildings. It also will be open to agricultural and industrial applications. The NC Program is a combination of the previously existing Nonresidential Retrofit and Nonresidential New Construction programs, as well as the custom track for measures previously utilized under the NP Program. Eligible measures will include any measure that saves natural gas, is found to be cost effective, and does not have an existing prescriptive rebate. Space heating, water heating, and process heating are expected to be the largest opportunities. The program also has a track for nonresidential customers who are gut renovating or constructing new commercial buildings. Projects will be reviewed by the program administrator, screened for cost effectiveness, and offered an incentive based on the financial characteristics of the project. The incentive for a single project will be capped at the lesser of the project's gas benefits, incremental cost, or $100,000.

The program is expected to cost $6.9 million in nominal dollars over five years and save 3,040 BBtus of natural gas over the lifetime of the measures installed. The program is projected to provide present value TRC net benefits of $4.4 million with a BCR of 1.35. The program will also save approximately 181,000 tons of CO_2 over the lifetime of the installed measures, which is equivalent to permanently removing over 3,000 cars from the road.

Q. Why are multi-family projects included in this program?

A. Multi-family buildings that serve more than four units through a single meter are served under the N/NT rate class. It is important that these types of buildings are not left out of the Consolidated EE&C Plan, as they present a unique opportunity for whole-building energy efficiency and conservation.

Q. Is the Nonresidential Custom Program a new program?

A. No. It is the continuation of the existing Nonresidential Retrofit Program, with the process applied to new construction and single-measure custom projects, to streamline program administration and provide more flexible options for the Company's nonresidential customers. The program has also been expanded to include DS and LFD customers, as well as Central Rate District customers, which has led to increased savings and participation projections. Due to longer lead times for nonresidential projects, the program is expected to ramp up more slowly than UGI Gas's other EE&C offerings. As a result, the program is not projected to reach its full participation potential until FY 2023.

F. COMBINED HEAT AND POWER PROGRAM

Q. Please describe the CHP Program.

A. The CHP Program provides incentives for CHP plants that have net-primary-energy savings and are cost effective under the TRC test. The program also seeks to promote projects that would contribute CO_2 emission reductions. The program would offer an incentive of $750 per kW, with a per project cap of $250,000 and no more than 50% of CHP project cost. Over the five years of the portfolio, the CHP Program is projected to cost $3.4 million, in nominal terms, and provide 26,336 BBtus in net-primary-energy savings over the lifetime of the installed projects. The program is expected to have a present value of TRC net benefits of $21.7 million with a BCR of 1.24. The program will also save approximately 2.6 million tons of CO_2 over the lifetime of the installed measures, which is equivalent to permanently removing over 44,300 cars from the road.

Q. What types of CHP projects will the program incentivize?

A. The program will target large commercial and industrial customers with high thermal and electric loads, such as hospitals, college campuses and multi-shift industrial customers. Due to the current state of avoided costs, UGI Gas anticipates that typically only larger CHP projects (over 1,000 kW) will be cost effective. However, UGI Gas will continue to monitor both the energy market and customer opportunities to address as wide a range of CHP technology types and sizes as possible.

Q. What updates were made to the CHP Program?

A. Updates were made to participation projections based on current program experience. Even with the addition of the Central Rate District territory, UGI Gas is projecting fewer and smaller units than the initial South and North EE&C Plans, with a corresponding drop in savings and budget.

G. PORTFOLIO-WIDE COSTS

Q. What do the portfolio-wide costs cover?

A. The portfolio-wide costs cover development, design, tracking, reporting, legal and administrative overhead that cuts across all the programs in the portfolio. This includes amortized costs for plan and portfolio development incurred for the Company's two existing gas EE&C Plans. Over the five-year period, portfolio-wide costs represent 8% of the portfolio's expenditures.

H. OTHER UPDATES

Q. What other updates are included in the Consolidated EE&C Plan?

A. The Consolidated EE&C Plan includes the removal of the Behavior and Education Program and a general update to avoided costs.

Q. Why did the Company not include the Behavior and Education Program in the Consolidated EE&C Plan?

A. The Behavior and Education Program is not included in the Consolidated Plan because UGI Gas has been able to achieve significant savings from its existing residential programs, well above original projections. UGI Gas is prioritizing portfolio spending on the RP Program and, to a lesser extent, the RR Program, both of which deliver longer-lived and higher savings per participant than a home energy reports-style program, such as the Behavior and Education Program.

Q. What updates were done to avoided costs?

A. UGI Gas developed avoided costs consistent with its current EE&C Plans, with some adjustments to account for the entirety of the consolidated utility territory. Gas prices were derived from more recent forward prices and the 2018 Annual Energy Outlook ("AEO") report. The marginal baseload pipeline resource was changed from Transco Zone 5 to Transco Zone 4 to better reflect the delivery point for marginal baseload supply to the Company's territory. Capacity costs were based on marginal peaking contracts to more realistically reflect the usage of seasonal gas supply. Section 1.8.2 of Exhibit TML-2 provides additional details on the avoided cost calculations.

VI. CONCLUSIONS AND RECOMMENDATIONS

Q. What conclusions do you reach?

A. I conclude that UGI Gas's proposed portfolio of EE programs and the CHP Program will be cost effective and economically beneficial to UGI Gas ratepayers and the economy of the UGI Gas territory and Pennsylvania.

Q. On the basis of these conclusions, what are your recommendations to the Commission?

A. I recommend that the Commission approve implementation of UGI Gas's five-year Consolidated EE&C Plan. Any delay in implementation represents delay of the benefits that will occur and loss of opportunities.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS EXHIBIT TML-1

THEODORE M. LOVE

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Professional Experience

Green Energy Economics Group, Inc. – Cuttingsville, VT
Partner 2017 to Present
Senior Associate and Data Scientist 2013 to 2017
Associate 2010 to 2013
Analyst 2007 to 2010
Providing research and technical assistance relating to the design, analysis, and implementation of energy utility demand-side management (DSM) programs for electric and natural gas service providers around the world; including ten states, two Canadian provinces, and China. Particularly focused on data analysis and building scalable tools to analyze everything from individual projects to programs to portfolios.

Alter & Rosen, LLP –New York, NY 2007 to 2010
Consultant
Managed the development of an online database management system for musical copyrights and brought on board paying beta users. Managed data entry, reporting, termination and reversion issues for transactions involving musical copyright catalogues valued at over $100 million.

AllianceBernstein LP –White Plains, NY 2006 to 2007
Client Reporting Analyst
Oversaw the monthly and quarterly report process for clients domiciled outside the United States. Increased by 150% the amount of accounts that met a fifth business day deadline. Transferred firm's quarterly reporting process to new system.

Education

Clark University – Worcester, MA
B.A. Magna cum Laude, *Mathematics and Computer Science*, 2006.

Kansai Gaidai University: Hirakata City, Osaka Japan.
Study Abroad Program, Spring Semester 2005

General Assembly: New York City, NY
Data Science Intensive Course, 2015

Recent Project Experience

Green Energy Economics Group, Inc.

Research on Leading Energy Efficiency Portfolios
Green Energy Economics Group - Vermont *(November 2007 – Present)*
- Maintain research and proprietary analysis on actual and projected results from over a dozen electric and natural gas demand side management (DSM) portfolios throughout North America;

Natural Gas Efficiency Options and EE&C Plan for Peoples Natural Gas
Peoples Natural Gas, Inc. – Pennsylvania *(September 2017 – Present)*
- Prepared report on program, sector, and portfolio-level cost and savings for 29 natural gas administrators in 11 States, and provided recommendations for potential natural gas DSM opportunities for Peoples Natural Gas
- Assist with stakeholder review process
- Developed five year $42 million Energy Efficiency and Conservation (EE&C) Plan, and provided testimony to support the adoption of the Plan (ongoing).

Development and Implementation of Energy Efficiency and Conservation Plans
UGI Utilities, Inc. – Pennsylvania *(June 2015 – Present)*
Assist UGI Utilities, Inc. and PNG with the development and approval of Energy Efficiency and Conservation (EE&C) Plans for their UGI Gas PNG Gas, and UGI Electric divisions, including:
- Developing an achievable efficiency scenarios for UGI Gas and PNG Gas.
- Designing a five-year, $27 million energy efficiency and conservation plan for UGI Gas. Submitting direct testimony on behalf of UGI Gas, Inc. on the design and implementation of the proposed plan (Docket No. R-2015-2518438)
- Designing a five-year $15 million energy efficiency and conservation plan for PNG Gas. Submitting direct testimony on behalf of PNG Gas, Inc. on the design and implementation of the proposed plan (Docket No. R-2016-2580030)
- Assisting with the design and implementation and reporting of the UGI Electric's voluntary EE programs. Designing and assisting with approval for a five-year $7.2 million electric energy efficiency and conservation plan (Docket No. M-2018-3004144)

Strategic Planning and Implementation of Five-year DSM Portfolio
Philadelphia Gas Work's (PGW) - Philadelphia, Pennsylvania *(August 2008 – Present)*
- Designed Phase II plan with PGW and submitted direct testimony supporting the plan on behalf of PGW (Docket No. P-2014-2459362)
- Member of lead consulting team that aided in the design and approval of PGW's five-year, $54 million portfolio of DSM programs;
- Providing ongoing technical assistance in the development of PGW's $35 million Phase II five year plan.

- Providing ongoing technical support in program design and implementation, including the roll-out of six programs that, combined since inception, have saved 120,000 MMBtus at a cost of approximately $17 million;
- Developed specifications for and currently collaborating with internal PGW staff on database system to track weatherization projects, rebate applications, and other information pertaining to PGW's DSM portfolio;
- Developed multiple Excel-based tools used by contractors to perform field audits, provide QA/QC, and track ongoing progress for contractors, programs, and the portfolio as a whole;
- Provided research and analysis support for multiple rounds of expert testimony before the Pennsylvania Public Utility Commission (Docket R-2009—2149884);
- Aided in the issuance of RFPs and selection of candidates for over $40 million in contracts;
- Major contributor to PGW's ongoing formal reporting and evaluation process, including the issuance of five implementation plans, three annual reports, and two impact evaluations.

Analytic and Technical Support for DSM Tracking Systems
PECO Energy Company – Pennsylvania *(September 2016 – December 2017)*
Commonwealth Edison Company – Illinois *(August 2017 – Present)*

- Subcontractor to ANB Systems Inc. to provide domain expertise and analytic support to rollout of enhanced tracking system.
- Developed dashboards and internal reports used by PECO's EM&V team, business planning, and various program and portfolio managers.
- Guided automation of PECO's six-month and annual reporting process.

Technical Assistance for Energy Efficiency Program Planning
Green Mountain Power - *Vermont* *(August 2012 – July 2017)*

- Developed multivariable regression model and framework to estimate the cost per kW to address a reliability gap in the St. Albans region with targeted energy efficiency.
- Reviewed and analyzed program proposals for the $20 million Community Energy & Efficiency Development Fund (CEED Fund), including the development of scoring and rebalancing mechanisms;
- Analyzed dataset of 5,000 custom business projects to establish models used for future planning exercises.
- Prepared report on uncounted benefits of renewable generation sources for Vermont.

Analysis of Energy Efficiency in British Columbia
BC Sustainable Energy Association & Sierra Club BC, *British Columbia (May 2011 – June 2014)*

- Provided comments and energy efficiency opportunities report for proceedings on FortisBC Gas and Electric's long-term DSM plans in December of 2013.

- Assisted on research for direct testimony on reasonableness of gas DSM Plan by Fortis Energy Utilities before the British Columbia Utilities Commission, BCUC Project No. 3698627;
- Technical support on assessment of FortisBC Electric's long-term DSM plan and corresponding expert testimony;
- Assistance with direct testimony and technical support on assessment of BC Hydro's long-term DSM plan, before the BCUC.

Energy Efficiency Potential in Oklahoma
Sierra Club, *Oklahoma* *(April 2011 – November 2011, December 2013 – January 2014)*
- Provided updated report for energy efficiency in Oklahoma and additional comments on PUC rulemaking for electric and gas utility programs.
- Preparation of report on energy efficiency potential for Oklahoma;
- Assistance with research and drafting comments on the US regional haze Federal Implementation Plan for the State of Oklahoma;
- Research and formulation of energy efficiency potential projections provided as part of expert testimony for Oklahoma Gas & Electric's rate case before the Corporation Commission of Oklahoma, Cause No. PUD 201100087.

Technical Assistance for Energy Efficiency Programs
Focus on Energy - *Wisconsin* *(June 2011 – August 2013)*
- Developed and customized cost-effectiveness calculators for Wisconsin's Focus on Energy portfolio of energy efficiency programs;
- Trained staff and other consultants on usage of tools and general economic analysis of energy efficiency programs;
- Provided QA/QC on cost-effectiveness analysis of 14 programs spending over $160 million in two years.

Chicagoland Energy Efficiency Portfolio
People's Gas - *Chicago, Illinois* *(September 2008 – January 2013)*
- Providing ongoing regulatory support;
- Provided cost-benefit analysis of various program scenarios and aided in the analysis of contractor bids;
- Customized excel-based portfolio and project cost-effectiveness tools to client's specifications.

Testimony Support for Expanding Gas Energy Efficiency in Pennsylvania
Citizens for Pennsylvania's Future, *Pennsylvania* *(July 2013 – September 2013)*
- Provided support on preparation of testimony regarding Peoples Gas of Pennsylvania's DSM plans, including preparation of benchmarking report and alternative scenario projections.

Energy Efficiency Potential in Texas
Sierra Club, *Texas* *(May 2012 – August 2012)*

- Research and development of alternative energy efficiency potential scenarios for the ten investor owned utilities (IOUs) in Texas;
- Development of comments for the Public Utility Commission of Texas;
- Development of presentation before the Energy Efficiency Incentive Program Committee.

Austin Energy's Energy Efficiency Potential
Austin City Council Consumer Advocate, *Austin, Texas* *(April 2012)*

- Research and development of alternative energy efficiency potential scenarios for Austin Energy.

Nevada Power's Energy Efficiency Potential
Sierra Club, *Nevada* *(November 2011 – June 2012)*

- Research on Nevada Power's Integrated Resource Plan (IRP) and development of alternative energy efficiency potential projections.

Comments on EmPower Maryland Programs
Sierra Club, *Maryland* *(September 2011 – October 2011)*

- Research for and development of comments on EmPower Maryland's energy efficiency programs, including the development of alternative energy efficiency potential projections.

Ontario Power Authority Field Audit Support Tool
Green Communities Canada - *Ontario, Canada* *(January 2011 – May 2011)*

- Collected and implemented specifications for updating the tool used by Ontario Power Authority's low-income program field agents to collect data and determine project net present values;
- Added custom features including customer input forms, saving and closing routines, and database file importing.

Energy Efficiency Potential in Arkansas
Sierra Club/Audubon Society, *Arkansas* *(September 2009 – March 2010)*

- Research and drafting assistance for expert testimony on energy efficiency' as an alternative to the White Bluff Steam Electric Station before the Public Service Commission of Arkansas, Docket No. 09-024-U.

Training for NGOs Working on Energy Efficiency Projects in China
ISC and NRDC – United States and China *(August 2008 – September 2010)*

- Developed training materials and provided remote and in-person training sessions on the economic and financial analysis of industrial retrofit projects for structuring and negotiating financial incentive offers to customers;
    - Worked with the Institute for Sustainable Communities (ISC) to aid its efforts to promote energy efficiency in the Guangdong and Jiangsu Provinces (February 2009 – September 2010);

- Worked with the National Resource Defense Council (NRDC) to aid in its efforts in China, especially in conjunction with a $100 million revolving loan fund from the Asia Development Bank (August 2008-January 2009).

Incentive Calculations for the Project Cost-effectiveness Analysis Tool (CAT)
Efficiency Vermont – Burlington, Vermont (November 2008 – June 2010)

- Aided in the design of a new approach to calculating incentives for custom energy efficiency projects based on financing and reaching a desired rate of return;
- Modified CAT's cash-flow projection engine, an Excel VBA system, to accommodate the new approach to incentives.

Vermont's 20-year Forecast of Electricity Savings from Sustained Investment
Efficiency Vermont – Burlington, Vermont (December 2008 – October 2009)

- Provided components of final report relating to long-term trends for the environment (climate change, land-use, and water-use), population growth, and governmental regulation;
- Provided additional technical support on electric demand-side savings potential.

Connecticut's Long Term Acquisition Plan
Connecticut Office of the Consumer Council – Connecticut (August – October 2008)

- Provided research and support for expert testimony regarding long-range energy-efficiency procurement plan of the Energy Conservation Management Board, on behalf of the Connecticut Office of Consumer Counsel.

Energy Efficiency Plans of BC Hydro and Terasen Gas
BC Sustainable Energy Association and
The Sierra Club - British Columbia, Canada (October 2008 – March 2009)

- Provided research and support for expert testimony and technical support on assessment of BC Hydro's long-term DSM plan, before the BCUC, on behalf of the BC Sustainable Energy Association and Sierra Club Canada (November 2008 – March 2009);
- Provided research and support for expert testimony on assessment of Terasen Gas conservation plans before the BCUC, on behalf of the BC Sustainable Energy Association and Sierra Club Canada (October 2008).

Testimony

1. **Pennsylvania PUC** P-2014-2459362, Philadelphia Gas Works Demand-Side Management Plan for FY 2016-202; Philadelphia Gas Works. May 2015.

   Analysis of Phase I DSM Plan and design of Phase II DSM Plan.

2. **Pennsylvania PUC** P-2015-2518438, UGI Utilities, Inc.- Gas Division Rate Case; UGI Utilities, Inc. January 2016.

   Energy efficiency & conservation plan and total resource cost implementation.

3. **Pennsylvania PUC** P-2016-2580030, UGI Penn Natural Gas, Inc. Rate Case; UGI Penn Natural Gas, Inc. January 2017.

   Energy efficiency & conservation plan and total resource cost implementation.

4. **Pennsylvania PUC** M-2017-2640306, Petition of Peoples Natural Gas Company LLC for Approval of its Energy Efficiency and Conservation Plan; Peoples Natural Gas –Peoples Division, Peoples Natural Gas – Equitable Division; January 31, 2018.

   Energy efficiency study, energy efficiency & conservation plan, and total resource cost implementation.

5. **Pennsylvania PUC** M-2018-3004144, Petition of UGI Utilities, Inc. – Electric Division for Approval of Phase III of Its Energy Efficiency and Conservation Plan; August 21, 2018.

   Electric energy efficiency and conservation plan development, projections, implementation, and EM&V.

Publications

Love, Theodore. "Using Open Data to Predict Energy Usage: What tax lot data can tell us about energy usage intensity in New York City". *Behavior Energy, and Climate Change Conference 2015*. Sacramento, CA

Plunkett, John, Theodore Love, Francis Wyatt. "An Empirical Model for Predicting Electric Energy Efficiency Acquisition Costs in North America: Analysis and Application". In *Proceedings of the ACEEE 2012 Summer Study on Energy Efficiency in Buildings*, #906, Washington, D.C.: American Council for an Energy Efficient Economy.

Gold, Elliott, Marie-Claire Munnelly, Theodore Love, John Plunkett, Francis Wyatt. "Comprehensive and Cost-Effective: A Natural Gas Utility's Approach to Deep Natural Gas Retrofits for Low Income Customers." In *Proceedings of the ACEEE 2012 Summer Study on Energy Efficiency in Buildings*, #442, Washington, D.C.: American Council for an Energy Efficient Economy.

UGI GAS EXHIBIT TML-2

UGI Utilities, Inc. – Gas Division

Consolidated Energy Efficiency and Conservation Plan October 1, 2019 – September 30, 2024

Filed: January 28, 2019

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1 Introduction and Background

1.1 Plan Overview

This plan provides a detailed description of the design and implementation of the energy efficiency and conservation portfolio ("EE&C Portfolio" or "Portfolio") that UGI Utilities, Inc. – Gas Division ("UGI Gas" or "the Company") is proposing to offer in its Consolidated Energy Efficiency and Conservation Plan ("EE&C Plan" or "Plan"). The Plan will have a five-year duration, beginning in UGI Gas's fiscal year ("FY") 2020 through FY 2024,[1] and will include both natural gas energy efficiency ("EE") programs and a combined heat and power ("CHP") program.

UGI Gas's EE&C Plan was developed based on the Company's two existing gas EE&C Plans for its South and North rate districts that were approved, respectively, as part of the UGI Gas base rate proceeding in 2016,[2] and as part of the UGI Penn Natural Gas, Inc. ("UGI-PNG") base rate proceeding in 2017[3]. As discussed in more detail below, the Plan contains the same types of programs, Technical Reference Manual ("TRM"), and Total Resource Cost ("TRC") Test that are employed for both the North and South Rate District Plans approved by the Pennsylvania Public Utility Commission ("Commission"). Though UGI Gas is not mandated to enact an EE&C Plan under Act 129 of 2008 ("Act 129"), UGI Gas's voluntary EE&C Plan was developed using the guiding principles of the Commission's Act 129 Phase III Implementation Order.[4]

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[1] UGI Gas's fiscal year runs October 1st to September 30th.
[2] *See Pa. PUC v. UGI Utilities, Inc.*, Docket No. R-2015-2518438 (Order entered Oct. 14, 2016) ("*UGI Gas Division Order*").
[3] See *PA. PUC v. UGI Penn Natural Gas, Inc*., Docket No. R-2016-2580030 (Order entered August 31, 2017) ("*PNG Order*").
[4] *See Energy Efficiency and Conservation Program*, Docket No. M-2014-2424864 (Order entered June 19, 2015) ("*Phase III Implementation Order*"), *clarified*, Docket No. M-2014-2424864 (Order entered Aug. 20, 2015).

Over the five years of the EE&C Plan, UGI Gas plans to spend $63.9 million on five energy efficiency programs and one CHP program.[5] Altogether, the EE&C Portfolio is cost-effective, providing $81.7 million in net resource benefits with a TRC benefit-cost ratio ("BCR") of 1.49, which generally increases the economic wellbeing of UGI Gas's customers.

The five energy efficiency programs are projected to cost $60.4 million and save 1,252 BBtus of natural gas during the first five years of the Plan, and 24,745 BBtus of natural gas over the lifetime of the measures installed. From a total resource perspective, the present value of benefits is $135.1 million, with $75.1 million in present value of costs, leading to a present value of net benefits of $60.0 million and a TRC BCR of 1.80. Furthermore, the energy efficiency programs are expected to save 77,717 MWh of electricity, 353 million gallons of water, create between 742 and 1,237 jobs, and avoid the emission of CO_2 equivalent to over 25,300 cars being removed from the road.

UGI Gas is also proposing the investment of $3.4 million in a CHP program over five years. This program would provide net energy savings to customers over the five years of the Plan of 1,756 BBtus, and 26,336 BBtus over the lifetime of the CHP projects installed. The CHP program will provide present value of net benefits of $21.7 million from a total resource perspective, with a TRC BCR of 1.24.

1.2 Natural Gas and Energy Efficiency

Natural gas is an abundant resource and an important component of the Pennsylvania economy. In 2014, Pennsylvania had the most shale gas proven reserves in the country, driven by the development of the Marcellus Shale,[6] and over 90% of the natural gas UGI Gas delivers to its customers comes from the Marcellus Shale. As a result of this reliable, local supply, UGI Gas customers have seen utility bills that are approximately 40% lower than 2008.

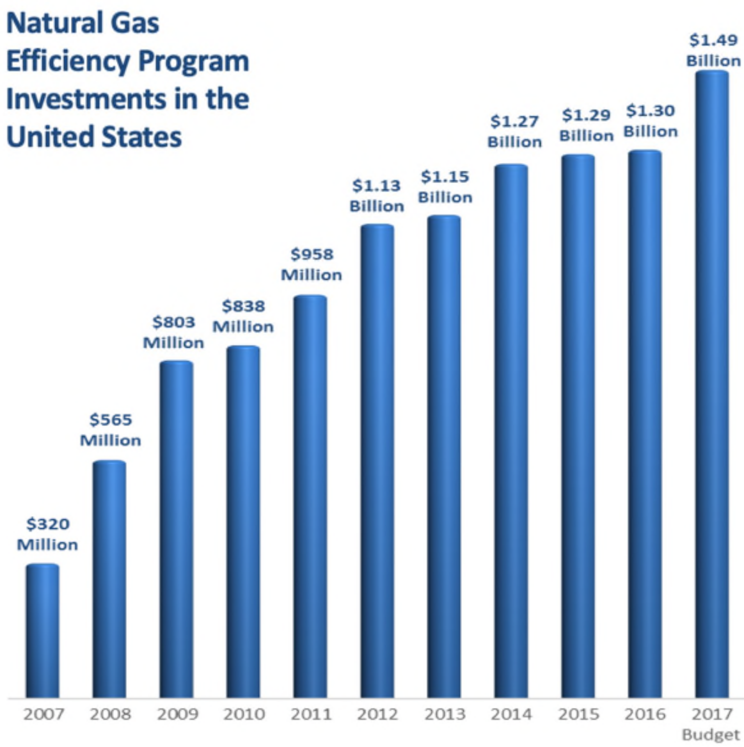
[5] All dollars are nominal unless otherwise noted.
[6] http://marcelluscoalition.org/2015/11/pa-drives-increase-in-u-s-natural-gas-abundance/

Natural gas also has many important advantages as an end-use fuel source. When compared to the use of electricity generated from natural gas or most other fuels, the direct end-use of natural gas is more efficient and environmentally preferable. Natural gas has a source-to-site efficiency of 92%, meaning the vast majority of the energy from natural gas is associated with on-site consumption. Electricity on the other hand, only has a source-to-site efficiency of 32%, meaning that less than one third of generated electric energy is used at the site.[7]

As natural gas has continued to grow in importance as a fuel source, natural gas energy efficiency programs have also shown steady growth. According to the American Gas Association ("AGA"), spending has gone up significantly over the past decade, nearly tripling from $565 million in 2008 to $1.49 billion budgeted for 2017, as shown in Figure 1. The AGA also estimates that natural gas utility energy efficiency programs saved 239 trillion Btu of energy and offset 12.5 million metric tons of carbon dioxide emissions in 2016. [8]

[7] Meyer, Richard. Dispatching Direct Use: *Achieving Greenhouse Gas Reductions with Natural Gas in Homes and Businesses*. American Gas Association: Washington, DC. November 11, 2015, p. 5.
[8] https://www.aga.org/globalassets/research--insights/reports/updated-energy-efficiency-slide-for-2018-aga-playbook.pptx

Figure 1. Growth of Natural Gas Energy Efficiency Program Spending[9]



The American Council for an Energy Efficient Economy ("ACEEE") State Energy Scorecard shows that spending on natural gas energy-efficiency programs has not just grown nationally, but also in the states surrounding Pennsylvania. New York has nearly tripled spending to $140 million between 2009 and 2017, and Maryland's spending increased from a few hundred thousand dollars annually in 2009 to $17 million in 2017.[10] Within Pennsylvania, a number of gas utilities have undertaken voluntary energy efficiency programs, including UGI Gas's North and South Rate Districts EE&C Plans and the second phase of Philadelphia Gas Works ("PGW") natural gas efficiency portfolio.

As the energy market is becoming increasingly customer driven, utilities around the country are recognizing the opportunity to drive economic growth and an efficient economy by sponsoring energy efficiency and conservation

[9] https://www.aga.org/research/reports/natural-gas-efficiency-programs-2016-program-year/ .
[10] ACEEE (American Council for an Energy-Efficient Economy), *The 2018 State Energy Efficiency Scorecard*, Weston Berg, et al, October 2018, p. 36.

programs. For natural gas utilities, the opportunity to invest in helping customers save money, increase comfort, and reduce the impact they have on the environment is now a crucial component of joining the next generation of energy utilities and benefiting the communities that they serve.

1.3 Goals

UGI Gas has the following core goals:

- Help its customers save energy cost-effectively through a holistic approach to energy efficiency and conservation;
- Avoid lost opportunities and provide deep levels of savings;
- Provide a wide range of services for its diverse customer base; and
- Contribute to the economic welfare of its customers and Pennsylvania.

In order to reach these goals, UGI Gas will utilize energy efficiency programs and a CHP program. For its energy efficiency programs, UGI Gas plans to invest approximately $60.4 million over five years with the goal of returning $60.0[11] million dollars in present value of total resource net benefits. As a secondary goal for efficiency programs, UGI Gas expects to save customers 24,745 BBtus of natural gas and 1.5 million tons of CO_2 emissions over the lifetime of installed measures during the five-year portfolio.

For the CHP program, UGI Gas plans to invest approximately $3.4 million over five years with the goal of returning $21.7 million dollars in present value of total resource net benefits.

1.4 Plan Development

The UGI Gas Consolidated EE&C Plan was developed based on the following principles:

[11] Includes Low-Income allocation of benefits based on a fixed BCR.

1. Maintain continuity with the current UGI Gas EE&C Plans while leveraging experience gained from the past two years of EE&C Program activity to improve program design and projections;
2. Extend the EE&C Plan opportunities to include UGI Central (formerly UGI Central Penn Gas, Inc.) rate district customers.
3. Extend opportunities to larger nonresidential customers in the DS and LFD rate classes.

UGI Gas market information was gathered and characterized, including avoided costs for natural gas and electricity, demographic, building stock, and equipment market characteristics. These were combined with the measure and project characterizations from the UGI Gas EE&C Portfolio for cost-effectiveness screening using the TRC Test. The cost-effective measures and projects were then used to calculate achievable savings and participation levels based on experience with the two current UGI Gas EE&C Plans. The achievable scenario was adjusted to allow for program ramp up, and budget constraints to come up with a final portfolio.

The proposed programs are based on the Company's two current EE&C Plans, with some updates based on lessons learned from previous program experience. Updates to program offerings include the combination of the Nonresidential New Construction and the Nonresidential Retrofit Program into the Nonresidential Custom Program and the decision not to include the Behavior and Education Program. The following table provides an overview of the proposed programs.

Table 1. Proposed Programs

Proposed Program	Existing Program	Disposition	Modifications
	Residential Programs		
Residential Prescriptive (RP)	Residential Prescriptive (RP)	Continued	Updated Projections

Residential New Construction (RNC)	Residential New Construction (RNC)	Continued	Updated Projections
Residential Retrofit (RR)	Residential Retrofit (RR)	Modified	Direct Install Component Added, Updated Projections
None	Behavior and Education (BE)	Discontinued	No longer included in Plan.
	Nonresidential Programs		
Nonresidential Prescriptive (NP)	Nonresidential Prescriptive (NP)	Continued	Updated Projections and Measures
Nonresidential Custom (NC)	Nonresidential Retrofit (NR)	Modified	Renamed and Added New Construction track, Updated Projections
Nonresidential Custom (NC)	Nonresidential New Construction (NNC)	Modified	Merged into NC Program
Combined Heat and Power (CHP)	Combined Heat and Power (CHP)	Continued	Updated Projections

1.4.1 Settlement Provisions from Previous Plans

The following settlement items from previous plans were adhered to in the development of the plan:

- All appliances and equipment qualifying for rebates or incentives under the EE&C plan must meet or exceed U.S. Department of Energy "EnergyStar" Minimum Standards to the extent such standards exist.
- UGI Gas will submit an annual report in January, approximately three months after the end of a program year. UGI Gas shall also hold an annual stakeholder meeting (Parties to this proceeding and other entities that express interest) to review and discuss the EE&C Plan's progress, as well as receive input from stakeholders on potential modifications to the EE&C Plan, if any. Each annual stakeholder meeting shall be held: (1) at a time and place chosen by UGI Gas; and (2) within three months after UGI Gas submits its EE&C Plan annual report to the Commission. UGI Gas will provide a copy of its annual EE&C Plan report to the stakeholders

at the time it is submitted to the Commission and will review and discuss the report at the stakeholder meeting.

- UGI Gas will include total resource cost test evaluations with and without the economic effects of carbon taxes and DRIPE in the evaluations of the cost effectiveness of the programs.
- UGI Gas will continue to coordinate with PA Housing Alliance and PA Housing Finance Agency and will continue to track participation for buildings with more than one unit.
- UGI Gas will continue to refer potentially eligible customers to its Low-income Usage Reduction Program ("LIURP") and will include LIURP messaging on applications and marketing materials, including a direct phone number to contact UGI Gas to pursue enrollment if the customer believes that they may qualify.
- UGI Gas will transfer $100,000 per year from the EE&C Plan to its Low-Income Usage Reduction Program (LIURP). For reporting purposes, the Company will utilize a TRC BCR value of 1.71 for the LIURP transfer, which is based on the overall TRC BCR for the combined residential programs, and is the same methodology used in settlement paragraph 34 for UGI North (formerly UGI-PNG).
- UGI Gas will, over the five-year term of the EE&C Plan, limit recoverable utility costs (including incentives, program administration, marketing, inspections and evaluation but excluding portfolio wide costs) for the NP and NC to 55 percent of the overall aggregated TRC costs for the NP and NC programs. Grant funding will be considered a source of participant funding. To the extent that UGI Gas deems that utility contributions in excess of 55 percent of overall program costs are required to achieve UGI Gas's desired participation levels, UGI Gas may voluntarily make the necessary contributions without EE&C cost recovery.
- The Company will not seek to recover in rates EE&C administrative costs in excess of the projections included in its filing.

Settlement provisions regarding the separation of residential and nonresidential new construction programs are no longer relevant, due to the updated program design.

Settlement provisions related to spending caps and benefit-cost ratios are no longer relevant due to updated projections and cost-effectiveness projections. Overall, spending was still restricted by a ceiling of 2% of revenue (approximately $17 million per year), which is in-line with Act 129 spending limits, and the overall portfolio has a TRC BCR greater than 1.0.

1.5 Total Plan Costs

The following table provides an overview of the spending by year and program for the total EE&C Plan. The maximum spend in a year is $14.1 million in FY 2024, approximately 1.5% of UGI Gas's FY 2019 budgeted revenues. This level is well under the 2% cap that Act 129 imposes on electric efficiency programs in Pennsylvania.[12]

Table 2. Projected Spending for Consolidated EE&C Plan by Program

Program	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
EE&C Total	**$10,449,050**	**$12,193,350**	**$13,168,200**	**$13,997,800**	**$14,062,400**	**$63,870,800**
Residential Prescriptive (RP)	5,030,900	5,833,900	6,364,100	6,574,900	6,494,900	30,298,700
Residential New Construction (RNC)	837,800	584,200	523,400	644,400	641,500	3,231,300
Residential Retrofit (RR)	1,521,000	2,068,000	2,165,000	2,105,000	2,105,000	9,964,000
Nonresidential Prescriptive (NP)	848,350	1,008,450	995,700	1,055,700	995,700	4,903,900
Nonresidential Custom (NC)	601,000	1,063,800	1,460,000	1,932,800	1,872,800	6,930,400
Portfolio-wide Costs	875,000	900,000	925,000	950,000	950,000	4,600,000
LIURP Transfer	100,000	100,000	100,000	100,000	100,000	500,000
EE Total	**9,814,050**	**11,558,350**	**12,533,200**	**13,362,800**	**13,159,900**	**60,428,300**
CHP Program	635,000	635,000	635,000	635,000	902,500	3,442,500

The following table provides the combined budgets for the EE programs and CHP Program by category for FY 2020, which is used as the reference year in UGI Gas's rate case filing.

Table 3. FY 2020 Budgets by Rate Class and Category

[12] *See* 66 Pa.C.S. § 2806.1(g) (limiting the total cost of an EDC's EE&C Plan to 2% of the EDC's total annual revenue as of December 31, 2006).

Program Category	R/RT	N/NT	DS	LFD	Total
Customer Incentives	$5,717,700	$527,175	$619,023	$408,153	$7,272,050
Administration	$2,075,770	$213,115	$179,180	$93,934	$2,562,000
Marketing	$258,000	$43,500	$50,450	$33,050	$385,000
Inspections	$137,000	$9,000	$8,800	$5,200	$160,000
Evaluation	$40,000	$0	$15,000	$15,000	$70,000
Total Expenses	**$8,228,470**	**$792,790**	**$872,453**	**$555,337**	**$10,449,050**

1.6 Efficiency Program Costs and Benefits

1.6.1 Efficiency Program Costs

The following table provides an overview of the spending by year and by sector on the EE programs. The EE programs will cost approximately $12.1 million per year over the five-year life of the EE&C Plan.

Table 4. Projected Efficiency Portfolio Budgets by Sector

Sector	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY ’20- ‘24
Nominal	**$9,814,050**	**$11,558,350**	**$12,533,200**	**$13,362,800**	**$13,159,900**	**$60,428,300**
Residential	$8,228,470	$9,315,096	$9,879,082	$10,147,468	$10,065,537	**$47,635,654**
Nonresidential	$1,585,580	$2,243,254	$2,654,118	$3,215,332	$3,094,363	**$12,792,646**

The following table shows the projected efficiency budgets by program.

Table 5. Projected Efficiency Portfolio Budgets by Program

Program	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY ’20-‘24
EE Total	**9,814,050**	**11,558,350**	**12,533,200**	**13,362,800**	**13,159,900**	**60,428,300**
Residential Prescriptive (RP)	5,030,900	5,833,900	6,364,100	6,574,900	6,494,900	30,298,700
Residential New Construction (RNC)	837,800	584,200	523,400	644,400	641,500	3,231,300
Residential Retrofit (RR)	1,521,000	2,068,000	2,165,000	2,105,000	2,105,000	9,964,000
Nonresidential Prescriptive (NP)	848,350	1,008,450	995,700	1,055,700	995,700	4,903,900
Nonresidential Custom (NC)	601,000	1,063,800	1,460,000	1,932,800	1,872,800	6,930,400
Portfolio-wide Costs	875,000	900,000	925,000	950,000	950,000	4,600,000
LIURP Transfer	100,000	100,000	100,000	100,000	100,000	500,000

The portfolio-wide cost lines from the previous table are costs that apply to all programs in the EE portfolio. They are costs incurred at the portfolio level for program development, design, tracking, reporting, and administrative overhead. Development costs for the portfolio occur in the first year as programs are designed and reporting infrastructure is put in place. Costs then fall sharply in the second year before climbing as the portfolio grows. In the final year, the portfolio wide costs represent 7% of the portfolio total cost, and, over the five-year period, they represent 8% of the portfolio's costs. The following table provides a portfolio-level look at costs by category.

Table 6. Projected Efficiency Portfolio Budgets by Category[13]

Category	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
EE Total	**$9,814,050**	**$11,558,350**	**$12,533,200**	**$13,362,800**	**$13,159,900**	**$60,428,300**
Customer Incentives	6,772,050	7,885,350	8,842,200	9,345,800	9,385,900	42,231,300
Administration	2,502,000	2,940,000	3,035,000	3,139,000	3,155,000	14,771,000
Marketing	345,000	373,000	389,000	399,000	400,000	1,906,000
Inspections	155,000	190,000	207,000	219,000	219,000	990,000
Evaluation	40,000	170,000	60,000	260,000	0	530,000

1.6.2 Natural Gas Savings

The following tables provide projected natural gas savings by program and sector for the energy efficiency programs in the EE&C Portfolio.

Table 7. Projected First Year Gas Savings by Program (MMBtus)

Program	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
Portfolio Total	**204,704**	**233,603**	**261,254**	**275,848**	**277,011**	**1,252,420**
Residential Prescriptive (RP)	107,515	123,609	136,827	139,642	139,642	647,234
Residential New Construction (RNC)	20,623	9,377	9,511	10,750	11,913	62,174
Residential Retrofit (RR)	17,325	24,340	24,841	24,841	24,841	116,188
Nonresidential Prescriptive (NP)	48,350	54,847	57,209	57,209	57,209	274,825
Nonresidential Custom (NC)	10,890	21,431	32,866	43,406	43,406	152,000

Table 8. Projected Lifetime Gas Savings by Program (MMBtus)

Program	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
Portfolio Total	**4,057,020**	**4,610,820**	**5,158,029**	**5,448,167**	**5,471,418**	**24,745,455**
Residential Prescriptive (RP)	2,081,972	2,393,590	2,649,411	2,703,966	2,703,966	12,532,905
Residential New Construction (RNC)	412,451	187,534	190,227	215,004	238,255	1,243,471
Residential Retrofit (RR)	296,969	415,413	423,873	423,873	423,873	1,984,002
Nonresidential Prescriptive (NP)	1,047,823	1,185,671	1,237,197	1,237,197	1,237,197	5,945,086
Nonresidential Custom (NC)	217,806	428,612	657,320	868,126	868,126	3,039,990

[13] Includes EE&C to LIURP transfer of $100,000 per year in Administration Costs.

Table 9. Projected Gas Savings by Sector (MMBtus)

Sector	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY ’20-‘24
First Year Gas Savings	**204,704**	**233,603**	**261,254**	**275,848**	**277,011**	**1,252,420**
Residential	145,463	157,325	171,179	175,233	176,395	**825,596**
Nonresidential	59,241	76,278	90,075	100,615	100,615	**426,824**
Lifetime Gas Savings	**4,057,020**	**4,610,820**	**5,158,029**	**5,448,167**	**5,471,418**	**24,745,455**
Residential	2,791,392	2,996,538	3,263,511	3,342,844	3,366,094	**15,760,378**
Nonresidential	1,265,629	1,614,282	1,894,518	2,105,324	2,105,324	**8,985,076**

1.6.3 Electric Savings

The following table shows electric savings for measures installed under the energy efficiency programs in the EE&C Portfolio. The electric savings are secondary savings from measures that primarily save natural gas, such as air-conditioning savings from higher insulation.

Table 10. Projected Electric Savings by Sector

Sector	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY ’20-‘24
First Year Energy (MWh)	**1,607**	**604**	**633**	**695**	**742**	**4,280**
Residential	1,546	529	544	595	642	**3,855**
Nonresidential	61	75	89	100	100	**425**
Lifetime Energy (MWh)	**30,849**	**10,513**	**10,987**	**12,211**	**13,157**	**77,717**
Residential	29,977	9,380	9,596	10,600	11,546	**71,099**
Nonresidential	871	1,133	1,391	1,611	1,611	**6,618**
Summer Peak (kW)	**647**	**158**	**130**	**150**	**159**	**1,244**
Residential	629	128	83	91	100	**1,031**
Nonresidential	18	30	47	59	59	**213**

1.6.4 Water Savings

This section contains ancillary water savings from gas efficiency measures that also save water, such as low-flow faucet aerators and showerheads.

Table 11. Projected Water Savings by Sector (Million Gallons)

Sector	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY ’20-‘24
First Year Water Savings	**4.62**	**5.55**	**5.72**	**5.72**	**5.72**	**27.32**
Residential (R/RT)	1.59	2.26	2.30	2.30	2.30	**10.75**
Nonresidential (N/NT)	3.03	3.30	3.41	3.41	3.41	**16.56**
Lifetime Water Savings	**60.96**	**71.49**	**73.59**	**73.59**	**73.59**	**353.22**
Residential (R/RT)	15.91	22.59	23.07	23.07	23.07	**107.70**
Nonresidential (N/NT)	45.05	48.90	50.52	50.52	50.52	**245.52**

1.6.5 Emission Reductions

This section contains projections for CO_2 emission reductions due to the energy efficiency programs. The total savings of 1.5 million tons of CO_2 is equivalent to removing 25,300 cars off the road. The following table breaks out the emission reductions due to gas savings and electric savings. While the emissions reductions are projected below, the main TRC test for the portfolio does not include any value for these emissions reductions.

Table 12. Projected CO_2 Emission Reductions by Energy Source (Short Tons)

Sector	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
First Year Reductions	**13,323**	**14,172**	**15,814**	**16,720**	**16,827**	**76,856**
From Gas Savings	11,975	13,666	15,283	16,137	16,205	**73,267**
From Electric Savings	1,348	507	530	582	622	**3,589**
Lifetime Reductions	**263,202**	**278,548**	**310,957**	**328,957**	**331,110**	**1,512,775**
From Gas Savings	237,336	269,733	301,745	318,718	320,078	**1,447,609**
From Electric Savings	25,867	8,815	9,212	10,239	11,033	**65,166**

1.6.6 Job Creation

Investing in cost-effective energy efficiency creates jobs in two ways, one direct and the other indirect, as discussed in a 2012 white paper from the ACEEE.[14] Direct job creation results from hiring related to implementing the programs. Indirect job creation results from the substitution of capital spent on natural gas with capital spent in the local economy. Additional jobs are created by the indirect or income effect from cost-effective energy efficiency investment. Further, the net economic benefits from efficiency investment reduce household and business gas bills and raise household disposable incomes and business profitability. Customers will tend to spend most of this additional money and save the rest. This additional spending creates a "multiplier" effect through the cycle of re-spending of the initial cost savings, which stimulates aggregate demand for goods and services. Satisfying increased demand for goods and services requires more labor. While some of the jobs created leak into the broader U.S. and global economy, a good portion (possibly higher than 80%) of jobs created due to energy efficiency stay within the Commonwealth. The

[14] "Energy Efficiency Job Creation: Real World Experiences" Bell, Casey J. American Council for an Energy-Efficiency Economy. October 2012.

approach of looking at net job creation through both direct means and with economic multiplier effects is endorsed in the 2012 white paper from ACEEE.[15]

The number of jobs created from investments in energy efficiency directly relates to the total resource value of the energy that these measures save. Studies of employment impacts of Demand Side Management (“DSM”) use energy savings as a surrogate for total resource value. A meta-study of U.S. data found that estimates for the number of jobs created had a wide range, but that most studies estimate that between 30 and 60 net jobs are created by saving one TBtu.[16] In New York, New Jersey, and Pennsylvania, the ACEEE projected that 164,320 jobs, or 59 for every TBtu saved, could be attributed to EE in 1997 through 2010.[17]

As shown in the following table, UGI Gas estimates that its gas energy efficiency programs portfolio will generate between 742 and 1,485 net additional jobs over the lifetime of the efficiency measures installed over the next five-years. This range is based on assuming that each TBtu of gas savings creates between 30 and 60 full-time equivalent jobs in Pennsylvania.

Table 13. Estimated Job Creation due to Energy Efficiency Programs

	30 Jobs/TBtu	40 Jobs/TBtu	50 Jobs/TBtu	60 Jobs/TBtu
RESIDENTIAL PROGRAMS				
FY 2020	84	112	140	167
FY 2021	90	120	150	180
FY 2022	98	131	163	196
FY 2023	100	134	167	201
FY 2024	101	135	168	202
TOTAL	**473**	**630**	**788**	**946**
NON-RESIDENTIAL PROGRAMS				
FY 2020	38	51	63	76
FY 2021	48	65	81	97
FY 2022	57	76	95	114
FY 2023	63	84	105	126

[15] Energy Efficiency Job Creation: Real World Experiences” Bell, Casey J. American Council for an Energy-Efficiency Economy. October 2012.
[16] Laitner, Skip, and Vanessa McKinney. June 2008. *Positive Returns: State Energy Efficiency Analyses Can Inform U.S. Energy Policy Assessments*. Washington, D.C.: American Council for an Energy Efficiency Economy.
[17] Nadel, Steven, Skip Laitner, Marshall Goldberg, Neal Elliott, John DeCicco, Howard Geller, and Robert Mowris. 1997. *Energy Efficiency and Economic Development in New York, New Jersey, and Pennsylvania. Washington, D.C.*: American Council for an Energy Efficiency Economy.

FY 2024	63	84	105	126
TOTAL	**270**	**359**	**449**	**539**
TOTAL PORTFOLIO				
FY 2020	122	162	203	243
FY 2021	138	184	231	277
FY 2022	155	206	258	309
FY 2023	163	218	272	327
FY 2024	164	219	274	328
TOTAL	**742**	**990**	**1,237**	**1,485**

1.7 CHP Program Costs and Benefits

The following table provides the annual projected budget for the CHP Program in nominal dollars.

Table 14. Projected CHP Program Budgets

Spending	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY ’20-‘24
Nominal	$635,000	$635,000	$635,000	$635,000	$902,500	**$ 3,442,500**

The following table provides the net primary energy savings installed annually for the CHP Program.

Table 15. Projected Net Primary Energy Savings from CHP (MMBtus)

Savings	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY ’20-‘24
First Year	339,710	339,710	339,710	339,710	396,905	**1,755,747**
Lifetime	5,095,656	5,095,656	5,095,656	5,095,656	5,953,578	**26,336,203**

The following table provides the net CO_2 emission reductions due to the CHP Program.

Table 16. Net CO_2 Emission Reductions due to CHP (Short Tons)

Savings	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY ’20-‘24
First Year	34,154	34,154	34,154	34,154	39,907	**176,524**
Lifetime	512,315	512,315	512,315	512,315	598,603	**2,647,862**

1.8 Cost-Effectiveness Analysis

The following table provides cost-effectiveness projections for the EE&C Portfolio using the TRC Test, which is the primary metric by which UGI Gas evaluates the EE&C Plan.

Table 17. TRC Cost-effectiveness Summary of EE&C Portfolio (2018$)

Program	Total Resource PV Benefits	Total Resource PV Costs	Total Resource PV Net Benefits	Total Resource BCR
EE&C Total	**$248,781,595**	**$167,052,056**	**$81,729,539**	**1.49**

Residential Prescriptive (RP)	66,906,943	36,799,435	30,107,508	1.82
Residential New Construction (RNC)	7,986,156	3,786,306	4,199,851	2.11
Residential Retrofit (RR)	11,876,481	10,010,434	1,866,047	1.19
Nonresidential Prescriptive (NP)	30,824,692	8,147,406	22,677,285	3.78
Nonresidential Custom (NC)	16,816,997	12,415,806	4,401,191	1.35
Portfolio-wide Costs	0	3,511,529	-3,511,529	0.00
LIURP Transfer	656,663	382,906	273,756	1.71
EE Total	**135,067,931**	**75,053,822**	**60,014,109**	**1.80**
CHP Program	113,713,664	91,998,234	21,715,430	1.24

While the portfolio is cost-effective using the primary TRC Test, if the values for demand-response induced pricing effects ("DRIPE") and internalized market prices for carbon dioxide ("CO_2") are included, the portfolio shows substantially more benefits. In particular, net benefits for the CHP Program are $117.3 million, more than six times the net benefits calculated using the primary TRC Test. Energy efficiency programs' TRC net benefits go over 60 percent to $97.3 million, and the TRC BCR for the entire EE&C portfolio goes from 1.44 to 2.28.

Table 18. TRC Cost-effectiveness Summary of EE&C Portfolio (2018$) including DRIPE and CO_2

Program	Total Resource PV Benefits	Total Resource PV Costs	Total Resource PV Net Benefits	Total Resource BCR
EE&C Total	**$381,693,459**	**$167,052,056**	**$214,641,404**	**2.28**
Residential Prescriptive (RP)	86,025,637	36,799,435	49,226,202	2.34
Residential New Construction (RNC)	9,477,571	3,786,306	5,691,266	2.50
Residential Retrofit (RR)	14,911,896	10,010,434	4,901,462	1.49
Nonresidential Prescriptive (NP)	39,700,986	8,147,406	31,553,580	4.87
Nonresidential Custom (NC)	21,457,045	12,415,806	9,041,239	1.73
Portfolio-wide Costs	0	3,511,529	-3,511,529	0.00
LIURP Transfer	835,609	382,906	452,703	2.18
EE Total	**172,408,745**	**75,053,822**	**97,354,923**	**2.30**
CHP Program	209,284,714	91,998,234	117,286,481	2.27

1.8.1 Cost-Effectiveness Analysis Methodology

The cost-effectiveness results reported in the Plan followed standard industry practices for utilizing the TRC Test for cost-effectiveness. The TRC Test methodology used is the same as that used by the Company in its current EE&C Plans for the North and South Rate Districts. To calculate benefits, projected natural gas, electricity, and water savings are multiplied by avoided costs, and this stream of future values is discounted to the present. For measures that have an increase in resource usage, such as CHP projects, the increase in usage may offset some, or all, of the positive benefit derived from resource savings. The cost side of the test consists of the present value of all incremental costs incurred by participants, including net operation and maintenance costs, and the non-incentive costs incurred by the portfolio administrator. If the benefits outweigh the costs (the benefit-cost ratio is above one), then the total cost of energy services for an average customer within the territory will fall and the portfolio is considered cost effective. Results for the Program Administrator Cost ("PAC") test are also included. The PAC only includes the costs for program administration and incentives, not additional customer costs. Since UGI Gas is a natural gas utility, the benefits for the PAC test are the natural gas savings. As per paragraph 41 of the UGI Gas Division rate case settlement, UGI Gas will present the results of the TRC Test with and without the value of DRIPE and CO_2.

The analysis used a real discount rate ("RDR") of 5.43%. The RDR was calculated using an assumption of a nominal discount rate ("NDR") of 7.54%, based on UGI Gas's weighted average cost of capital ("WACC"), and an inflation rate of 2.0%.

1.8.2 Avoided costs

UGI Gas developed avoided costs consistent with its current EE&C Plans, with some adjustments to account for the entirety of the consolidated utility territory. The costs of baseload and peaking capacity were included (paralleling the inclusion of generation capacity in the electric avoided costs), along with avoidable local distribution costs.

The avoided costs for baseload were computed as the cost of the Transco FT contract, plus commodity priced at Transco Zone 4, using futures pricing from November 9, 2018. Futures prices were blended with 2018 Annual Energy Outlook ("AEO") values through 2030, and the Annual Energy Outlook projections were used thereafter. To slow the transition to the AEO prices, blending was based on the cube root (the ⅓ power) of the ratio of open contracts in each year to the open contracts for 2019.

The avoided costs for heating load were computed as the commodity costs of the projected Henry Hub price, minus the basis to Transco Zone 4, plus the commodity charge and gas retention from the Transco FT tariff. This was then combined with capacity costs for a typical marginal peaking contract, computed as the capacity-weighted average annual charge in dollar per peak dekatherm ("dth") for the five most expensive peaking contracts from UGI Energy Services, of $222/dth. This capacity is applied to the contribution of the load-weighted design-day peak, equivalent to 74.2 HDD, and divided over the annual heating load, which averages about 5,665 HDD.

Avoided transmission and distribution, demand-reduction induced price effect ("DRIPE") and internalized market price of carbon dioxide ("CO_2") were unchanged from the original South EE&C Plan Filing.

Evaluation of some gas-efficiency programs and CHP also requires estimates of avoided electric costs. Electric avoided costs were taken directly from the analysis performed by the Statewide Evaluator ("SWE"), and utilizes a blend of 50% PPL Electric Utilities Corporation, 25% FirstEnergy – Penelec, and 25% FirstEnergy - MetEd, the major electric distribution companies ("EDCs") whose service territories overlap with UGI Gas's service territory, restated to constant 2018 dollars.[18] Both the electric and gas avoided costs are also provided with the benefits of reduced supply prices and the internalized market price for carbon emissions included. A table showing the annual values for gas and electric avoided costs is included in Appendix 1.6.

[18] Act 129 SWE Distributed Generation Potential Study, Docket No. M-2014-2424864 (February 13, 2015).

1.9 Implementation

1.9.1 Program Staging

All programs are projected to be operating by October 1, 2019, since all the programs currently exist already as part of the Company's two existing gas EE&C Plans. However, programs may have some ramp up time due to the addition of customers in the current Central Rate District who do not currently have access to a gas EE&C Plan. Under the Consolidated EE&C Plan, eligible customers in the UGI Central Rate District will be allowed to participate upon the effective date of new rates.

1.9.2 Marketing

General Awareness and Branding

UGI Gas will leverage much of the already established existing marketing infrastructure. This will create cost-effective and consistent messaging regarding UGI Gas's efficiency and conservation efforts. Marketing efforts may include, but not be limited to, www.ugi.com/savesmart, print, radio and digital advertisements, along with billboards, social media, bill inserts and trade ally outreach. Once a customer reaches the website, the customer will be funneled towards appropriate programs and incentives through targeted links. While the website will be a primary component of marketing the Plan, it will also be supplemented with additional marketing collateral such as flyers and application forms.

Multi-family Outreach

UGI Gas will market directly to residential multi-family customers and multi-family new construction, including master-metered multifamily residences. These efforts will focus on residents, landlords, and management companies, regardless of the rate class structure of the property. In addition, efforts will be made to coordinate with the Pennsylvania Housing Alliance and the Pennsylvania Housing Finance Agency.

Low-income Customers

Customers who contact UGI Gas or its Conservation Service Providers ("CSPs") with interest in participating in the EE&C Plan will be informed that they might qualify for the Low-Income Usage Reduction Program ("LIURP") if they are income qualified. Any interested customers will be referred to UGI Gas's LIURP.

UGI Gas will transfer $100,000 per year from the Consolidated EE&C Plan to its Low-Income Usage Reduction Program (LIURP). For reporting purposes, the Company will utilize a TRC BCR value of 1.71 for the LIURP transfer, which is based on the overall TRC BCR for the combined residential programs, and is the same methodology used in settlement paragraph 34 for UGI North (formerly UGI-PNG).

Targeted Outreach and Partnerships

UGI Gas will continue to leverage and enhance partnerships with trade allies. These efforts are likely to be the best way to drive nonresidential participation. Successful activities involve all sectors within the community and may include as activities such as:

- Partnering with local businesses and trade organizations (builders, contractors, plumbers, HVAC service providers, equipment suppliers, etc.) to familiarize them with program opportunities, energy efficiency practices and implementation requirements and to utilize them, where appropriate, as one of the program's service delivery channels.
- Targeting equipment manufacturers, distributors, installation contractors and retailers/vendors to make sure they offer high-efficiency equipment and can make customers aware of available incentives.
- Connecting with local business organizations to provide opportunities to address their specific needs and translate them to their tenants, management, and facility operations personnel.
- Working with administrators of Act 129 EDCs' EE&C Plans to combine marketing and delivery options and address all aspects of efficiency at the same time.

1.9.3 Administration

The table below describes the main roles in the management of the EE&C Plan.

Table 19. Overview of Administration Roles

Role	Description
Plan Administrator	Primarily responsible for program and portfolio planning, management and reporting. Supervises and manages all other roles.
Implementation and Design Consultants	Provides assistance in the design and implementation on multiple aspects of the portfolio, including, but not limited to, program design, reporting, marketing, and training. UGI Gas will leverage internal resources wherever possible to provide these services.
Implementation Contractor	Directly responsible for main aspects of program delivery, including but not limited to, customer engagement and retention, technical assistance, measure installation, rebate processing, program tracking, and reporting.
Third-party Inspector	Responsible for measure and project inspections separately from the implementation contractor.
Evaluator	Performs independent program and portfolio evaluations that are used to verify savings and guide future plans.

1.9.4 Reporting

UGI Gas will submit an annual report on the EE&C Plan each January, three months after the close of the program year. This report will provide information on activity for the previous year and progress towards five-year goals, including, but not limited to:

- First year and lifetime savings;
- Participation;
- Spending;
- Cost-effectiveness;
- Highlights of portfolio and program activity; and
- Updates to program delivery and design.

In order to tie savings and costs together as effectively as possible, results will be reported based on commitments made. UGI Gas will also report on any participation by buildings with more than one unit.

1.9.5 Program Flexibility

To make sure that the EE&C Portfolio is able to address changing market conditions and improve service delivery as quickly as possible, UGI Gas requires flexibility in the allocation of budgets and implementation of program improvements. This plan document provides the principles and five-year goals that UGI Gas is seeking, but certain adjustments, such as providing incentives for new measures or moving budgets between years and programs, may be required to meet these goals. UGI Gas will include any such adjustments in its annual report but does not anticipate seeking initial approval for such updates. However, UGI Gas will file an updated EE&C Plan in anticipation of material changes that may have a serious effect on five-year goals, such as:

- The addition or removal of a program;
- A need for total funding levels above those approved for the five-year period; and
- Significant changes to cost-effectiveness projections, such as an update to avoided costs or a large reduction in portfolio spending projections.

1.9.6 Technical Reference Manual

To maintain consistency with existing gas efficiency programs in Pennsylvania, UGI Gas will utilize the same Technical Reference Manual ("TRM") that is currently used in the Company's existing gas EE&C Plans. Any results from program evaluations that affect deemed savings calculations will be added to the TRM and provided in annual report filings.

1.9.7 Tracking System

UGI Gas will require that CSPs collect all relevant customer, application, measure, and contractor information and that this data is provided to UGI Gas in a timely fashion. UGI Gas will in turn maintain a program and portfolio-level aggregation of this information to be used for program management and assessment, as well as for annual reporting.

1.9.8 Third-party inspections

Each program will have a third-party inspector, separate from the contractor that performed the work, who will solicit customer feedback and will examine whether the work was done properly and whether the installed measures match the application data. Inspections for large, complex, and custom projects will be mandatory. Inspection rates for prescriptive programs will be designed to gather a statistically significant sample of program activity. See individual program plans for additional details.

1.9.9 Evaluation, Measurement, and Verification

UGI Gas will monitor the ongoing progress of the EE&C Plan to provide the highest possible service to customers, while maintaining rigorous processes and controls to ensure that savings and costs are being properly accounted for. UGI Gas will closely track program data, perform independent inspections of completed projects, and perform periodic evaluations for all programs.

UGI Gas will evaluate each of its programs once adequate participation levels have been reached and a full 12 months of post-participation billing data has been collected. The programs may be evaluated again after another two years have passed. As part of the initial program development, UGI Gas will work with the selected evaluator to establish the methodology and goals of the process evaluation. Initial objectives include:

- Verifying energy savings and associated costs;
- Assessing market attitudes towards the program, including contractors, customers, and efficient equipment suppliers; and
- Measuring the effectiveness of current program design, marketing, and service delivery.

The evaluation section of the individual program descriptions includes additional details on evaluation schedules and goals unique to that program.

2 Program Plans

2.1 Residential Prescriptive

Objective	The Residential Prescriptive (RP) program is designed to overcome market barriers to energy efficient space and water heating equipment in the residential sector through rebates and customer awareness. The objective of the program is to avoid lost opportunities by encouraging consumers to install the most efficient gas heating technologies available when replacing older, less efficient equipment. The program also aims to strengthen UGI Gas's relationship with HVAC contractors, suppliers, and other trade allies.
Eligible Rate Class	R/RT, N/NT
Cost Effectiveness	***Five-Year Cost-Effectiveness Results (2018$)***
Savings Projections	***Five-Year Savings Projections***

Five-Year Cost-Effectiveness Results (2018$)

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC Test	$ 66,906,943	$ 36,799,435	$ 30,107,508	1.82
Gas Admin Test	$ 66,740,097	$ 22,995,133	$ 43,744,963	2.90

Five-Year Savings Projections

	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
Natural Gas (MMBtus)						
First Year	107,515	123,609	136,827	139,642	139,642	**647,234**
Lifetime	2,081,972	2,393,590	2,649,411	2,703,966	2,703,966	**12,532,905**
Electric Energy (kWh)						
First Year	64,784	74,399	82,419	84,038	84,038	**389,677**
Lifetime	712,620	818,387	906,613	924,416	924,416	**4,286,451**

	Peak (kW)	**-**	**-**	**-**	**-**	**-**	**-**
	Water (Gallons)						
	First Year	**-**	**-**	**-**	**-**	**-**	**-**
	Lifetime	**-**	**-**	**-**	**-**	**-**	**-**

Budget Projections

Five-Year Budgets (Nominal)

Category	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
Customer Incentives	$4,675,900	$5,378,900	$5,953,100	$6,078,900	$6,078,900	**$28,165,700**
Administration	151,000	159,000	166,000	167,000	167,000	**810,000**
Marketing	123,000	134,000	143,000	145,000	145,000	**690,000**
Inspections	81,000	92,000	102,000	104,000	104,000	**483,000**
Evaluation	-	70,000	-	80,000	-	**150,000**
Total	**$5,030,900**	**$5,833,900**	**$6,364,100**	**$6,574,900**	**$6,494,900**	**$30,298,700**

Participation Projections

Five-Year Participation Projections

Measure	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
Furnace - ENERGY STAR	4,392	5,024	5,567	5,655	5,655	**26,293**
Boiler - (94+ AFUE)	330	378	418	426	426	**1,978**
Combi Boiler - (94+ AFUE)	1,035	1,201	1,327	1,365	1,365	**6,293**
Smart Thermostat – ENERGY STAR	2,722	3,126	3,463	3,531	3,531	**16,373**
Tankless Water Heater - ENERGY STAR	648	748	828	849	849	**3,922**
Total	**9,127**	**10,477**	**11,603**	**11,826**	**11,826**	**54,859**

Program Design

The RP program follows the same design as the current UGI North and UGI South programs of the same name. The same measures from the current program are also included; however, incentive levels were adjusted to reflect updated incremental cost data.

The RP program offers rebates for qualifying residential-sized space and water heating equipment.

	Customer rebates can be issued via mail or in the form of an instant rebate issued by qualified participating contractors or equipment distributors. Customers will be made aware of opportunities through traditional marketing efforts, such as bill inserts and media advertisements, as well as from installation contractors. For most measures, customers will have a contractor install the measure and receive a cash rebate to offset most of the incremental cost of the higher efficiency equipment. Smaller measures, such as Wi-Fi enabled thermostats, will only require a valid proof of purchase before a cash rebate is issued. UGI Gas will continue to examine other equipment for potential inclusion in the program, as well as the relative market adoption of equipment already receiving incentives. If program funds begin to run low in a given year, incentive levels may be lowered, or equipment removed from the program if additional budget adjustments cannot be made. UGI Gas will aim to provide as little interruption to customers as possible due to such adjustments.
Target Market and End Uses	The RP targets residential and small commercial consumers who use natural gas to heat their homes and/or generate hot water. In general, the program aims to incentivize only the highest levels of efficient equipment on the market. The minimum level of efficiency for measures offered through the RP program will be ENERGY STAR®, when available, and in some cases may exceed ENERGY STAR®. On the space heating side, the program provides incentives for ENERGY STAR® labeled smart thermostats, furnaces, high efficiency boilers, and combination boilers. ENERGY STAR® smart

	thermostats offer the potential for deeper savings than traditional programmable thermostats due to the wide range of features and feedback they offer. ENERGY STAR® requirements for furnaces drive customers toward the highest efficiency tier of condensing units (95+ AFUE) and require efficient fans that save electricity. The program would also require boilers to go towards the highest efficiency tier with an AFUE of at least 94. Finally, offering incentives for combination space and water heating boilers addresses two types of end-use with one piece of equipment. These "combi boilers" also address issues with orphaned water heaters having existing atmospheric venting systems that are no longer adequate, when switching to condensing heating equipment. The program also addresses water heating savings by offering incentives for ENERGY STAR® tankless water heaters.

<table>
<tr><td>Financial Incentives</td><td>Incentives were designed to be in line with other offerings in the region and/or cover approximately two-thirds of the incremental cost of the measure. The table below lists the proposed incentive schedule.

Proposed Residential Prescriptive Program Rebates (Nominal)

<table>
<tr><th>Equipment</th><th>Minimum Efficiency</th><th>Proposed Incentive</th><th>Maximum Incentive</th></tr>
<tr><td>Smart Thermostat</td><td>ENERGY STAR®</td><td>$100</td><td>$100</td></tr>
<tr><td>Furnace</td><td>ENERGY STAR®</td><td>$500</td><td>$500</td></tr>
<tr><td>Boiler</td><td>94+ AFUE</td><td>$1,200</td><td>$1,500</td></tr>
<tr><td>Combi Boiler</td><td>94+ AFUE</td><td>$1,500</td><td>$1,800</td></tr>
<tr><td>Tankless Water Heater</td><td>ENERGY STAR®</td><td>$400</td><td>$400</td></tr>
</table>
All equipment besides the Wi-Fi thermostat must be powered by natural gas.</td></tr>
<tr><td>Marketing Approach</td><td>The RP program will be a cornerstone of the two-pronged marketing approach for the portfolio. The program is expected to be a large portion of the general call-to-action on the residential side as well as a key part of trade ally outreach efforts. This will include placement on UGI's energy efficiency website, www.ugi.com/savesmart, as well as a general social media push. This program will also include more tailored messages for developers, owners, and managers of larger multi-family properties to make sure that high efficiency options are considered when bulk-purchasing decisions may be made. The RP program will also be regularly featured in UGI Gas monthly bill inserts.</td></tr>
</table>

Evaluation, Measurement, and Verification	<u>Quality Assurance</u> All applications will require proof of purchase and a valid UGI Gas account number. Rebates received as an instant rebate via a qualified participating contractor or equipment distributor will be accompanied by an invoice showing the point of sale discount passed on to the customer. The rebate processor will verify that the equipment is eligible for the rebate based on the model number before issuing any rebate. The program's rebate processor will maintain a real-time database of rebate activity, which will be periodically reviewed by UGI Gas and stored separately for long-term purposes. A third-party inspector will perform on-site inspections on approximately five percent (5%) of non-thermostat equipment rebates and approximately three percent (3%) of Wi-Fi thermostat rebates in order to obtain a statistically significant sample of activity. The inspection will consist of verifying that the rebated equipment is installed and operational and conclude with a short informational interview with the participant. <u>Evaluations</u> A third-party vendor began evaluation activity on the existing UGI South and North programs at the end of FY 2018. This vendor will continue to provide evaluation activity in conjunction with all applicable UGI Gas EE&C programs. The program evaluation activity is expected to continue on a biennial basis, with the next evaluation scheduled for FY 2021.

Program Administration	<u>Rebate Processing</u> The rebate processor will accept customer applications, track and verify application information, notify the customer of any issues, maintain a call center, and report results to UGI Gas. The rebate processor may also be responsible for other rebate programs in order to streamline portfolio management. UGI Gas plans to continue to utilize the existing rebate processor to help ensure a seamless transition and process for customers. <u>Marketing and Outreach</u> The UGI Gas marketing vendor and the UGI Gas internal team will handle marketing and outreach for the RP program. <u>Inspector</u> A separate contractor from the one installing any equipment will perform on-site inspections and collect customer feedback and is expected to be the same as that utilized by UGI Gas in order to standardize inspection workflows and data collection. <u>Evaluator</u> A third-party evaluator will be retained to perform regular evaluations approximately every two years.
Special Notes	In addition to offering cash rebates and instant rebates via a qualified participating contractor, customers will also have the option to purchase qualified smart thermostats via an online marketplace operated by the UGI Gas rebate processor. This website offers the most popular

	qualified smart thermostats, with the rebate being discounted from the purchase price instantly during checkout.

2.2 Residential New Construction

Objective	The Residential New Construction (RNC) Program is designed to overcome market barriers to energy efficient space and water heating equipment, as well as high efficiency thermal envelopes, in the residential new construction sector through rebates offered to builders and developers, and general potential buyer awareness. The objective of the program is to avoid lost opportunities by encouraging builders and developers to install the most efficient gas heating technologies available instead of less efficient baseline equipment, as well as promote thermal envelope best practices. The program also aims to strengthen UGI Gas's relationship with builders, HVAC contractors, suppliers, and other trade allies.
Eligible Rate Class	R/RT
Cost Effectiveness	***Five-Year Cost-Effectiveness Results (2018$)***

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC	$ 7,986,156	$ 3,786,306	$ 4,199,851	2.11
PAC	$ 4,951,531	$ 2,494,428	$ 2,457,103	1.99

Savings Projections

Five-Year Savings Projections

	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
Natural Gas (MMBtus)						
First Year	20,623	9,377	9,511	10,750	11,913	**62,174**
Lifetime	412,451	187,534	190,227	215,004	238,255	**1,243,471**
Electric Energy (kWh)						
First Year	1,426,485	376,258	381,582	430,882	478,210	**3,093,416**
Lifetime	28,529,691	7,525,152	7,631,640	8,617,640	9,564,200	**61,868,323**
Peak (kW)						**945.3**

	616.2	110.0	64.8	73.0	81.4	
Water (Gallons)						
First Year	-	-	-	-	-	**-**
Lifetime	-	-	-	-	-	**-**

Budget Projections

Five-Year Budgets (Nominal)

Category	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
Customer Incentives	$573,800	$358,200	$329,400	$372,400	$412,500	**$2,046,300**
Administration	153,000	155,000	126,000	142,000	158,000	**734,000**
Marketing	55,000	55,000	54,000	54,000	55,000	**273,000**
Inspections	16,000	16,000	14,000	16,000	16,000	**78,000**
Evaluation	40,000	-	-	60,000	-	**100,000**
Total	**$837,800**	**$584,200**	**$523,400**	**$644,400**	**$641,500**	**$3,231,300**

Participation Projections

Five-Year Participation Projections

Project Type	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
HERS Track New Home	328	333	270	304	339	**1,574**
ENERGY STAR New Home	142	144	117	133	146	**682**
Total	**470**	**477**	**387**	**437**	**485**	**2,256**

Program Design

Addressing efficiency when a building is first built is the cheapest and longest lasting way to change energy consumption patterns. The RNC program offers incentives to builders and/or developers for going beyond building code to reduce natural gas consumption. UGI Gas will continue to use the current program administrator to review customer applications, assess the project plans, verify that each project meets program eligibility requirements, help the customer to achieve the highest feasible and cost-effective savings, and issue rebate payments.

	Similar to the program design of the Act 129 129 EDCs, the program focuses on a whole home energy efficient building practice that is evaluated by savings above code, as established through a Home Energy Rating System score ("HERS rating" or "HERS score"). The HERS rating will evaluate the savings above a baseline code construction home and will issue incentives based on the natural gas savings achieved. The RNC program encourages participants to go as deep as possible by addressing the space heating system, water heating system, and building envelope.
Target Market and End Uses	The RNC program targets all new residential construction projects (including "gut rehab") contemplating use of natural gas to provide space and hot water heating. For the purposes of this program, gut rehabilitation is defined as a project where the interior space of the building exposes the studs or two or more of the mechanical systems are being replaced and are required to meet current energy code standards. In general, the program aims to incentivize only the highest levels of efficient equipment and construction practices on the market. The RNC program takes a whole-building approach, acquiring savings from multiple measures compared to a baseline building just meeting code. For single family and small multi-family buildings, measures might include thermal envelope insulation, heating equipment, and water heating equipment and fixtures.
Financial Incentives	Residential customers will receive a lump sum incentive for achieving the program required level of savings over code and/or a designated HERS rating score that will be designed to represent an average saving over code. An additional incentive category will be created to more deeply

	incentivize homes that achieve ENERGY STARY certification in addition to the required level of savings over code and/or designated HERS score. The maximum incentive that UGI Gas will offer is \$55/MMBtu. The following table provides an overview of proposed savings levels and associated incentives. <table><tr><th>Fiscal Year</th><th>Code Baseline</th><th>Savings Over Code</th><th>Base Incentive (\$/MMBtu)</th><th>Incentive ENERGY STAR® (\$/MMBtu)</th></tr><tr><td>FY 2020</td><td>2009 IECC</td><td>30%</td><td>\$25.00</td><td>\$30.00</td></tr><tr><td>FY 2021</td><td>2015 IECC</td><td>10%</td><td>\$35.00</td><td>\$40.00</td></tr><tr><td>FY 2022-2024</td><td>2015 IECC</td><td>15%</td><td>\$40.00</td><td>\$45.00</td></tr></table>
Marketing Approach	The RNC program will focus on tailored messages for developers and builders (including ENERGY STAR® builders) to ensure that high efficiency options are considered when engaging in major rehab projects as well as in new construction. UGI Gas will also explore ways in which to highlight the efficiency of homes to potential buyers, including through social media and signage placed at model homes.
Evaluation, Measurement, and Verification	<u>Quality Assurance</u> All applications will require information confirming installation and proof of UGI Gas service for heating. Inspections will be performed on 5% of residential new construction projects. Inspections must verify that the measures proposed for the building were installed as planned and that savings targets have been met and must conclude with a short informational interview with the owner and/or developer. The program's rebate processor will maintain a real-time database of rebate

	activity, which will be periodically reviewed by UGI Gas and stored separately for long-term purposes. <u>Evaluations</u> The program evaluation activity will be expected to continue seamlessly with the current evaluation of the UGI North and South programs. This vendor will continue to provide evaluation activity in conjunction with all applicable UGI Gas EE&C programs.
Program Administration	<u>Technical Assistance and Rebate Processing</u> UGI Gas will continue to use the current program administrator to review customer applications, assess the project plans, verify that each project meets program eligibility requirements, help the customer to achieve the highest feasible and cost-effective savings, and issue rebate payments. <u>Marketing and Outreach</u> The UGI Gas marketing vendor and the UGI Gas internal team will handle marketing and outreach for the RNC program. <u>Inspector</u> A separate contractor will perform on-site inspections and collect customer feedback. The same firm responsible for providing technical assistance may perform this role. <u>Evaluator</u>

	A third-party evaluator will be retained to perform regular evaluations approximately every two years.
Special Notes	UGI Gas will follow the guidance from the Act 129 SWE regarding the baseline code level from which the program counts savings. Currently, UGI Gas anticipates that the code baseline for savings purposes will be IECC 2009 until Phase IV of Act 129. The new construction market is highly cyclical and participation levels in the program will be highly influenced by broader economic trends beyond the control of UGI Gas.

2.3 Residential Retrofit

Objective	The Residential Retrofit (RR) Program is designed to overcome market barriers to energy efficiency in the existing residential sector through rebates offered either to customers undergoing a retrofit project or to their installation contractor(s). The program encourages improvements to the thermal envelope of the structure, particularly reductions in building air leakage and increases in insulation levels, as well as installation of the most efficient gas heating technologies. The program also aims to strengthen UGI Gas's relationship with Home Performance contractors, suppliers, and other trade allies.
Eligible Rate Class	R/RT

Cost Effectiveness

Five-Year Cost-Effectiveness Results (2018$)

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC	$ 11,876,481	$ 10,010,434	$ 1,866,047	1.19
PAC	$ 11,073,033	$ 9,311,785	$ 1,761,248	1.19

Savings Projections

Five-Year Savings Projections

	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
Natural Gas (MMBtus)						
First Year	17,325	24,340	24,841	24,841	24,841	**116,188**
Lifetime	296,969	415,413	423,873	423,873	423,873	**1,984,002**
Electric Energy (kWh)						
First Year	55,115	77,955	79,587	79,587	79,587	**371,830**
Lifetime	734,895	1,036,163	1,057,682	1,057,682	1,057,682	**4,944,103**
Peak (kW)	12.9	18.0	18.3	18.3	18.3	**85.9**
Water (Gallons)						

	First Year	1,588,215	2,255,265	2,302,911	2,302,911	2,302,911	**10,752,212**
	Lifetime	15,908,479	22,590,040	23,067,294	23,067,294	23,067,294	**107,700,400**

Budget Projections

Five-Year Budgets (Nominal)

Category	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
Customer Incentives	$468,000	$650,000	$663,000	$663,000	$663,000	**$3,107,000**
Administration	933,000	1,273,000	1,297,000	1,297,000	1,297,000	**6,097,000**
Marketing	80,000	89,000	89,000	89,000	89,000	**436,000**
Inspections	40,000	56,000	56,000	56,000	56,000	**264,000**
Evaluation	-	-	60,000	-	-	**60,000**
Total	**$1,521,000**	**$2,068,000**	**$2,165,000**	**$2,105,000**	**$2,105,000**	**$9,964,000**

Participation Projections

Five-Year Participation Projections

Project Type	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
Customer Receiving Assessments	2,000	2,840	2,900	2,900	2,900	**13,540**
Assessments Converted to Full Projects	360	500	510	510	510	**2,390**

Note: Full projects are also included in the count of customers receiving assessments

Program Design

The RR program offers incentives to customers retrofitting or weatherizing their homes by installing qualifying residential-sized space and water heating equipment, smart thermostats, and making thermal envelope improvements through use of approved contractors who may also receive an incentive to encourage comprehensiveness.

Customers must have an in-home assessment performed, which will cost up to $100. The assessment includes the direct installation of energy saving measures as well as a visual

	inspection of the thermal envelope and the space and water heating equipment in the home. Direct install measures can include, but not be limited to, energy saving measures such as ENERGY STAR smart thermostats, low flow devices, and water heater tank temperature set back. After the assessment, the customer receives a list of recommended efficiency measures, in addition to those that were directly installed. The customer can then have a contractor perform the recommended measures, after which they receive an incentive. Audits and thermal envelope improvements must be made by a contractor previously selected by the program as meeting program standards for high quality and technical performance. The rebate will be given to the customer upon submission of suitable documentation. Thermal envelope improvement rebates will require submittal of pre-post blower door measurements to document leakage rate reductions, and pre-post R-values, along with affected square footage, to document insulation improvements. Program participation levels will dictate allocation of funds from year to year, as well as the incentive levels offered. Initially, both participating customers and contractors each will be given an incentive that has been calculated based on first-year MMBtu projected savings. UGI Gas will aim to provide as little interruption as possible to the general community due to any program adjustments made to accommodate market conditions.
Target Market and End Uses	The RR program targets all residential homes that can benefit from improved space and water heating efficiency by encouraging a whole house approach to consider the full implications of

	specific measures to the overall performance of the house. The program offers a low-cost direct install Home Energy Assessment, with the goal of convincing home owners to go for a more comprehensive project. For comprehensive projects, the program aims to incentivize only the highest levels of efficient equipment on the market and the overall reduction in gas usage, including the interactive effects of equipment efficiency and thermal envelope improvements. A Home Energy Assessment may include, but is not limited to, the following gas saving measures: • ENERGY STAR® Smart Thermostat • Kitchen and Bathroom Faucet Aerator • Low flow Showerhead • Water Heater Tank Temperature Turndown In addition, the assessment may include the installation of health and safety measures, such as a Carbon Monoxide Detector. A comprehensive project is a project that goes beyond a Home Energy Assessment to include air sealing, insulation, and installing equipment such as, ENERGY STAR® certified furnaces, high efficiency boilers, and combination boilers as part of the home retrofit package. To qualify for even the lowest incentive tier, customers are guided toward the highest efficiency units as well as envelope improvements.
Financial Incentives	Customers will pay up to $100 for a home energy assessment, and contractors will be

	compensated up to $200 plus the cost of installed measures for a home energy assessment. The customer fee may be waived for qualifying low-income customers that are not eligible for LIURP services due to usage levels, or as a marketing promotion to assist with program ramp-up. Incentives for comprehensive jobs are designed to be in line with other offerings in the region and/or other companion programs in the UGI Gas portfolio such as the RP program. UGI Gas anticipates an incentive of approximately $55 per first year MMBtu savings for eligible projects. This incentive is designed to offset most of the incremental cost of the higher efficiency equipment and to provide a significant contribution to the cost of qualifying thermal envelope improvements.
Marketing Approach	Customers will be made aware of the RR program through the general media and bill inserts, as well as through equipment distributors, Home Performance contractors, and others in a position to affect equipment installation and thermal envelope improvement choices. The contractor network will play a large role in generating program leads. Approved program contractors will be encouraged to do their own marketing to enlist high quality leads for promoting high lead conversion rates, and to up-serve comprehensive retrofit packages qualifying for the highest incentive tier(s). They will be supported in these efforts through training and the development of co-branding materials that the contractor can use to promote the program.
Evaluation, Measurement, and Verification	<u>Quality Assurance</u> A contractor approved by UGI Gas will supervise all assessments and installation work. All approved contractors must employ a BPI certified employee to conduct both the in-home energy

	assessment and as crew leader for the installation of weatherization measures. Approved contractors must employ site technicians and site supervisors with BPI professional certifications appropriate to their duties. The approved contractor must also be trained in program protocols, and the contractor's first three projects will require confirmation of quality installation by an approved third party before moving from probationary status to becoming fully approved. Subsequent contractor work will be sampled up to 10% of projects submitted. Following approval into the program, an approved contractor will be required to meet a variety of criteria to remain in good standing with the program. These criteria will include, but not be limited to, customer satisfaction, quality assurance results, program activity, and ongoing training. <u>Rebate Processing</u> UGI Gas will continue to use the current program administrator to review customer applications, assess the project plans, verify that each project meets program eligibility requirements, help the customer to achieve the highest feasible and cost-effective savings, and issue rebate payments. <u>Evaluations</u> A third-party vendor will continue to provide evaluation activity in conjunction with all applicable UGI Gas EE&C programs. The next evaluation for the program is scheduled in FY 2022.
Program Administration	<u>Contractor Network</u> UGI Gas will put in place an approved contractor network that will perform energy audits, natural gas retrofit projects, and submit project and incentive application information to the program

	manager. <u>Program Manager</u> As part of the scope of work for the program administrator duties, UGI Gas will engage a program manager to oversee the contractor network, accept program applications, track and verify application information, communicate with customers if necessary, and report results to UGI Gas. <u>Marketing and Outreach</u> The UGI Gas marketing vendor and the UGI Gas internal team will handle marketing and outreach for the RR program. <u>Inspector</u> A separate contractor will perform on-site inspections and collect customer feedback. The inspector may also spend a portion of their time directed towards onsite mentoring for contractors. The program manager may perform the inspection role. <u>Evaluator</u> A third-party evaluator will be retained to perform an evaluation once a year's worth of post-installation data is available for the first year of the updated program design activity, in FY 2022.
Special Notes	UGI Gas will explore ways in which to encourage contractors to go after deeper savings. This may include setting aside a portion of incentives to go directly towards contractors in the form of a performance bonus.

2.4 Nonresidential Prescriptive

Objective	The Nonresidential Prescriptive (NP) Program is designed to overcome market barriers to energy efficient equipment in the small business and commercial sector through rebates and customer outreach. The objective of the program is to encourage business owners to install the most efficient gas heating and process technologies available to replace older, less efficient equipment. The program also aims to strengthen UGI Gas's relationship with HVAC contractors, suppliers, and other trade allies.
Eligible Rate Class	N/NT, DS, LFD
Cost Effectiveness	***Five-Year Cost-Effectiveness Results (2018$)***

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC	$ 30,824,692	$ 8,147,406	$ 22,677,285	3.78
PAC	$ 29,572,845	$ 3,827,949	$ 25,744,895	7.73

Savings Projections

Five-Year Savings Projections

	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
Natural Gas (MMBtus)						
First Year	48,350	54,847	57,209	57,209	57,209	**274,825**
Lifetime	1,047,823	1,185,671	1,237,197	1,237,197	1,237,197	**5,945,086**
Electric Energy (kWh)						
First Year	49,305	53,075	54,546	54,546	54,546	**266,017**
Lifetime	644,116	685,945	700,654	700,654	700,654	**3,432,022**
Peak (kW)	6.3	6.8	7.0	7.0	7.0	**34.0**
Water (Gallons)						
First Year	3,026,890	3,297,976	3,413,079	3,413,079	3,413,079	**16,564,102**
Lifetime	45,047,023	48,902,518	50,523,665	50,523,665	50,523,665	**245,520,535**

Budget Projections

Five-Year Budgets (Nominal)

Category	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY ’20-‘24
Customer Incentives	$708,350	$817,450	$853,700	$853,700	$853,700	**$4,086,900**
Administration	76,000	77,000	77,000	77,000	77,000	**384,000**
Marketing	54,000	54,000	54,000	54,000	54,000	**270,000**
Inspections	10,000	10,000	11,000	11,000	11,000	**53,000**
Evaluation	-	50,000	-	60,000	-	**110,000**
Total	**$848,350**	**$1,008,450**	**$995,700**	**$1,055,700**	**$995,700**	**$4,903,900**

Participation Projections

Five-Year Participation Projections

Measure Name	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20 - FY '24
Commercial Space Heating						
Commercial Boiler (ENERGY STAR)	143	159	166	166	166	**800**
Unit Heater (Warm Air)	162	181	189	189	189	**910**
Unit Heater (Infrared)	54	61	63	63	63	**304**
Steam Trap (<15 PSIG)	117	132	137	137	137	**660**
Commercial Water Heating						
Commercial Water Heater (Storage)	45	50	53	53	53	**254**
Commercial Water Heater (Tankless)	45	50	53	53	53	**254**
Commercial Kitchen						
Fryers (ENERGY STAR - Small Vat)	57	65	68	68	68	**326**
Fryers (ENERGY STAR - Large Vat)	6	7	7	7	7	**34**
Griddle (ENERGY STAR - 6 SF)	20	23	24	24	24	**115**
Griddle (ENERGY STAR - 8 SF)	8	8	8	8	8	**40**
Griddle (ENERGY STAR - 10SF)	4	5	5	5	5	**24**
Dishwasher (Low Temp - Under Counter)	18	20	21	21	21	**101**
Dishwasher (Low Temp - Stationary Single Tank Door)	21	23	24	24	24	**116**
Dishwasher (Low Temp - Single Tank Conveyor)	3	3	3	3	3	**15**
Dishwasher (High Temp - Under Counter)	21	23	24	24	24	**116**
Dishwasher (High Temp - Stationary Single Tank Door)	8	9	9	9	9	**44**
Dishwasher (High Temp - Single Tank Conveyor)	4	4	4	4	4	**20**
Total	**736**	**823**	**858**	**858**	**858**	**4,133**

Program Design	The NP offers rebates for qualifying equipment for three different applications; commercial-sized space heating, commercial-sized water heating, and commercial kitchens. Customers will be made aware of opportunities through traditional marketing efforts, such as bill inserts and media advertisements, installation contractors, and supply houses. Customers will have a contractor install the measure and receive a cash rebate to offset most of the incremental cost of the higher efficiency equipment. To relieve busy business owners of the paperwork, UGI Gas will also explore batching rebates and paying them directly to contractors and/or supply houses, with the rebate amount clearly indicated on the participant's invoice. The NP program offers rebates for qualifying commercial-sized space heating, water heating, commercial kitchen, and custom applications. Customers will be made aware of opportunities through traditional marketing efforts, such as bill inserts and media advertisements, contractors, and supply houses. Customers will have a contractor install the measure and receive a cash rebate to offset most of the incremental cost of the higher efficiency equipment. UGI Gas will continue to examine other equipment for potential inclusion in the program, as well as the relative market adoption of equipment already receiving incentives. If program funds begin to run low in a given year, incentive levels may be lowered, or equipment may be removed from the program if additional budget adjustments cannot be made. UGI Gas will aim to provide as little interruption to customers as possible due to such adjustments.
Target Market and End Uses	The NP program will serve the small business and commercial market such as office buildings,

	restaurants, and agricultural facilities, and will target three main end-uses. The first and largest end-use targeted is space heating, through commercial boilers, unit heaters, infrared heaters, and steam traps. The second target end-use is commercial water heaters. The last end-use is for addressing both cooking and hot water heating through a variety of commercial kitchen equipment.
Financial Incentives	Incentives were designed to be generally in-line with the UGI North and South programs of the same name. Incentives are designed to offset approximately two-thirds of the incremental cost to install the efficient equipment. The table below lists the proposed incentive schedule, with the addition of some new kitchen equipment and the removal of medium- and high-pressure steam traps (which will be addressed through the Nonresidential Custom program).

Proposed Nonresidential Prescriptive Program Rebates (Nominal)

Equipment	Minimum Efficiency	Proposed Incentive
Commercial Boiler (>= 300MBh)	ENERGY STAR	$2 / MBh + $2,000
Unit Heater (Warm Air/Low Intensity Infrared)	90+ Et/AFUE	$2 / MBh
Steam Trap	<15 PSIG	$50
Commercial Water Heater	ENERGY STAR®	$4 / MBh
Commercial Fryer	ENERGY STAR®	$500
Commercial Fryer (Large)	ENERGY STAR®	$750
Commercial Griddle	ENERGY STAR®	$600
Dishwasher (Low Temp – Undercounter)	ENERGY STAR®	$100
Dishwasher (Low Temp – Door)	ENERGY STAR®	$800
Dishwasher (Low Temp – Conveyor)	ENERGY STAR®	$1,000
Dishwasher (High Temp – Undercounter)	ENERGY STAR®	$700
Dishwasher (High Temp – Door)	ENERGY STAR®	$400
Dishwasher (High Temp – Conveyor)	ENERGY STAR®	$1,100

All equipment must be powered by natural gas, except for commercial dishwashers.

Marketing	The NP marketing approach focuses on targeted outreach to trade allies and supply houses.

Approach	Outreach efforts will attempt to reach the decision maker at the time of, and in advance of, the need for equipment replacement. UGI Gas will provide regular outreach and training sessions on efficiency opportunities with HVAC contractors, heating suppliers, kitchen equipment suppliers, local business organizations, and other parties that deal with commercial equipment to provide education on opportunities for engagement with the program, hand out rebate applications, and encourage the stocking of high efficiency equipment. Good penetration rates will rely heavily on an educated contractor network to understand how to up-serve participants with more efficient products when a service call is requested, or new equipment is needed. Contractor training will be provided to those already part of the existing contractor network and qualified for commercial work. UGI Gas will promote the program through its energy efficiency website, www.ugi.com/savesmart, and other marketing activities.
Evaluation, Measurement, and Verification	<u>Quality Assurance</u> All applications will require proof of purchase and a valid UGI Gas account number. All rebates will require proof of equipment installation, including information about the installing contractor. The rebate processor will verify that the equipment is eligible for the rebate based on the model number before issuing any rebate. The program's rebate processor will maintain a real-time database of rebate activity, which will be periodically reviewed by UGI Gas and stored separately for long-term purposes. A third-party inspector will perform on-site inspections on approximately five percent (5%) of all

	prescriptive rebates in order to get a statistically significant sample of ongoing activity. The inspection will consist of verifying that the rebated equipment is installed and operational and conclude with a short informational interview with the participant. Evaluations The program evaluation activity will be expected to continue seamlessly with the current evaluation of the UGI South program. A third-party vendor began evaluation activity on the existing UGI South program in September of 2018. This vendor will continue to provide evaluation activity in conjunction with all applicable UGI Gas EE&C programs.
Program Administration	Rebate Processing The rebate processor will accept customer applications, track and verify application information, notify the customer of any issues, maintain a call center, and report results to UGI Gas. The rebate processor may also be responsible for other rebate programs in order to streamline portfolio management. UGI Gas plans to continue to utilize the existing rebate processor to help ensure a seamless transition and process for customers. Marketing and Outreach The UGI Gas marketing vendor and the UGI Gas internal team will handle marketing and outreach for the NP program. Inspector

	A separate contractor from the one installing any equipment will perform on-site inspections and collect customer feedback and is expected to be the same as that utilized by UGI Gas to standardize inspection workflows and data collection. Evaluator A third-party evaluator will be retained to perform evaluations approximately every two years.
Special Notes	Due to the complex nature of the nonresidential equipment market, the exact mix of measures and adoption of different technologies is not easily predicted. While UGI Gas is confident that the projected budget levels are appropriate, the exact mix of measures may vary.

2.5 Nonresidential Custom

Objective	The Nonresidential Custom (NC) Program will provide incentives for overcoming market barriers for natural gas efficiency in commercial, industrial, and multifamily buildings. This can be through the natural replacement of equipment not covered in the NP Program, the retrofits of existing buildings, or by incenting natural gas energy savings in new construction or gut renovations.
Eligible Rate Class	N/NT, DS, LFD
Cost Effectiveness	***Five-Year Cost-Effectiveness Results (2018$)***

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC	$ 16,816,997	$ 12,415,806	$ 4,401,191	1.35
PAC	$ 16,559,226	$ 5,115,917	$ 11,443,309	3.24

Savings Projections

Five-Year Savings Projections

	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
Natural Gas (MMBtus)						
First Year	10,890	21,431	32,866	43,406	43,406	**152,000**
Lifetime	217,806	428,612	657,320	868,126	868,126	**3,039,990**
Electric Energy (kWh)						
First Year	11,361	22,372	34,514	45,525	45,525	**159,299**
Lifetime	227,224	447,449	690,285	910,509	910,509	**3,185,977**
Peak (kW)	11.6	23.2	40.4	52.0	52.0	**179.1**
Water (Gallons)						
First Year	-	-	-	-	-	**-**
Lifetime	-	-	-	-	-	**-**

Budget Projections	***Five-Year Budgets (Nominal)***

Category	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY ’20-‘24
Customer Incentives	$346,000	$680,800	$1,043,000	$1,377,800	$1,377,800	**$4,825,400**
Administration	214,000	276,000	344,000	406,000	406,000	**1,646,000**
Marketing	33,000	41,000	49,000	57,000	57,000	**237,000**
Inspections	8,000	16,000	24,000	32,000	32,000	**112,000**
Evaluation	-	50,000	-	60,000	-	**110,000**
Total	**$601,000**	**$1,063,800**	**$1,460,000**	**$1,932,800**	**$1,872,800**	**$6,930,400**

Participation Projections	***Five-Year Participation Projections***

Project Type	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY ’20-‘24
C&I Retrofit	30	59	90	119	119	**417**
C&I New Construction	2	4	7	9	9	**31**
Total	**32**	**63**	**97**	**128**	**128**	**448**

Program Design	The NC program combines the existing Nonresidential Retrofit (NR) and Nonresidential New Construction (NNC) programs offered by the Company under its current EE&C Plans, as well as the custom measure track from the existing NP Program. The NC program offers incentives to commercial buildings and multi-family projects that wish to upgrade some portion of an existing building’s performance or build a new building that includes cost-effective efficiency upgrades over a baseline code building practice. A technical assistance provider will evaluate projects for both savings opportunities and cost effectiveness. A custom package of measures will be determined that is cost-effective and an incentive offer will be extended to the customer based on the project’s financial characteristics. The customer then has a set amount of time to perform the upgrades and receive a test-out audit after which the incentive will be paid.

Target Market and End Uses	The NC program primarily targets commercial buildings and multi-family housing projects but is also open to agriculture and industrial applications. Any cost-effective measure that saves natural gas is eligible, with space heating, water heating, and process heating expected to be the largest opportunities. The NC program is also expected to cover technology with more site-specific applications, such as heat-recovery systems, controls, range-hood ventilation make-up air systems, and other. The NC program will be a source for potential technologies to include as prescriptive rebates.
Financial Incentives	Incentives for NC projects will all be based on the financial characteristics of the project. UGI Gas will negotiate with the customer to find an incentive that makes the project attractive enough for the customer to pursue without paying too much of the incremental cost. The first approach for calculating an incentive will be to determine an acceptable internal rate of return ("IRR") for the project that the customer will accept. A secondary approach will be to buy down the project's simple payback to between 5 and 10 years. The incentive for a single project will be capped at the lesser of the project's gas benefits, incremental cost, or $100,000.
Marketing Approach	Customers will be made aware of the NC program through the general media and bill inserts, as well as through equipment distributors, HVAC and plumbing contractors, housing program administrators, and others in a position to affect equipment installation and thermal envelope improvement choices.
Evaluation, Measurement,	<u>Quality Assurance</u>

and Verification	The administrator will monitor all projects from the outset. This includes monitoring the installation specifications and practices as well as the final project inspection to verify that all program requirements have been met for issuance of the requested incentive. <u>Evaluations</u> The program is projected to have a full evaluation in FY 2021 and in FY 2023. Since the number of projects anticipated to be completed under the program is small, evaluations will be more focused on a "case study" approach that verifies performance once a project is complete and sufficient post data is collected.
Program Administration	<u>Administrator</u> Due to the limited number of projects anticipated in the NC program, UGI Gas will manage the program internally. Technical review of projects, as well as assisting potential customers with including efficiency in their program design will be administered by UGI Gas EE&C Staff. A separate program tracking system that includes efficiency modeling and calculations will be utilized by the UGI Gas EE&C Staff. <u>Evaluator</u> A third-party evaluator will be retained to perform an evaluation approximately every two years.

2.6 Combined Heat and Power

Objective	The Combined Heat and Power (CHP) Program seeks to promote the installation of cost-effective and net-primary-energy-saving CHP projects and provide meaningful CO_2 emission reductions. A CHP plant produces electricity at a commercial or industrial site while at the same time using the waste heat from the production of the electricity to serve a thermal load. Net efficiencies come from the recovered heat that is typically wasted in grid electricity production and avoided transmission and distribution losses from delivering the electricity from the generator to the customer site.
Eligible Rate Class	DS, LFD
Cost Effectiveness	***Five-Year Cost-Effectiveness Results (2016$)***
Savings Projections	***Five-Year Savings Projections***

Five-Year Cost-Effectiveness Results (2016$)

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC	$113,713,664	$91,998,234	$21,715,430	1.24

Five-Year Savings Projections

	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY ’20-‘24
Net Primary Energy Savings (MMBtus)						
First Year	339,710	339,710	339,710	339,710	396,905	**1,755,747**
Lifetime	5,095,656	5,095,656	5,095,656	5,095,656	5,953,578	**26,336,203**
Net Customer Gas Usage Increase (MMBtus)						
First Year	236,517	236,517	236,517	236,517	276,428	**1,222,495**
Lifetime	3,547,752	3,547,752	3,547,752	3,547,752	4,146,424	**18,337,432**

Budget Projections	***Five-Year Budgets (Nominal)***
Participation Projections	***Five-Year Participation Projections***
Program Design	The CHP program is a rollout of the same program as that offered under the UGI North and South EE&C Plans. Customers that are considering CHP need to submit the project details including CHP installation costs, annual electricity production, and gas usage before and after the CHP project is completed. Based on the particular CHP project details, verified by UGI Gas or its contractor, UGI Gas will determine whether it is cost-effective from the TRC perspective and reduces net primary energy usage. If these criteria are met, then the CHP project is eligible for an incentive from UGI Gas. Though the customer has primary responsibility for developing the CHP costs, savings, and technical details, UGI Gas may provide some technical assistance, as well as business development for new projects.

Five-Year Budgets (Nominal)

Category	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
Customer Incentives	$500,000	$500,000	$500,000	$500,000	$750,000	**$2,750,000**
Administration	60,000	60,000	60,000	60,000	60,000	**300,000**
Marketing	40,000	40,000	40,000	40,000	40,000	**200,000**
Inspections	5,000	5,000	5,000	5,000	7,500	**27,500**
Evaluation	30,000	30,000	30,000	30,000	45,000	**165,000**
Total	**$635,000**	**$635,000**	**$635,000**	**$635,000**	**$902,500**	**$3,442,500**

Five-Year Participation Projections

Project Type	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY '20-'24
1121 kW CHP	0	0	0	0	1	**4**
3326 kW CHP	2	2	2	2	2	**7**
Total	**2**	**2**	**2**	**2**	**3**	**11**

Target Market and End Uses	The CHP Program targets large commercial and industrial customers with high thermal and electric loads. This program is most likely applicable to customers with year-round thermal requirements and high hours of use. Customer types that are likely candidates include hospitals, campuses and multi-shift industrial. Based on current avoided electric and gas avoided costs, only larger CHP projects (over 1,000 kW) are typically cost effective from the TRC perspective. If avoided costs change or the costs for micro turbines decline, then some smaller projects may become cost effective. UGI Gas will continue to closely monitor the CHP market and identify opportunities for all ranges of CHP technology and sizes.
Financial Incentives	$750/kW with a maximum of $250,000 per CHP project and no more than 50% of the CHP project cost.
Marketing Approach	UGI Gas will leverage its Relationship Managers to identify specific customers that may be likely candidates for CHP.
Evaluation, Measurement, and Verification	Every CHP project will be inspected, and documentation reviewed to ensure that the expected technology is correctly installed and operational. A third-party evaluator will be chosen to assess the actual versus projected electric and gas, generation and usage, respectively. Since the number of projects anticipated to be completed under the program is small, evaluations will be more focused on a “case study” approach that verifies performance once a project is complete and sufficient post data is collected.

Program Administration	The CHP program may be implemented either solely by UGI Gas or with assistance from an implementation contractor.
Special Notes	The CHP Program's costs and savings will be reported separately from the other efficiency programs, due to this program's increase in gas usage, whereas the other efficiency programs decrease gas usage. While UGI Gas is asking for general flexibility in annual program costs for the entire EE&C Portfolio, this flexibility is particularly important for the CHP program. CHP projects are complex and require long-term planning. Moreover, incentives represent a large percentage of the program budget. Because of these factors, it is difficult to predict the outcome for a single year. UGI Gas will limit its total spending to the five-year projected total spending, and under-spending from one year may be carried over to the next year.

3 Appendices

3.1 Avoided Cost Tables

<u>Gas Avoided Costs (2018$)</u>

	Baseload $/MMBTU	Space heating $/MMBTU	Water heating $/MMBTU	DRIPE $/MMBTU	CO2 $/MMBTU
2019	4.62	10.28	6.04		
2020	4.63	10.21	6.03	0.87	
2021	4.74	10.25	6.12	0.98	
2022	4.83	10.29	6.19	1.05	1.46
2023	4.99	10.42	6.35	1.09	1.55
2024	5.16	10.55	6.50	1.07	1.65
2025	5.32	10.68	6.66	1.05	1.74
2026	5.39	10.71	6.72	0.94	1.84
2027	5.52	10.82	6.84	0.87	1.93
2028	5.53	10.80	6.84	0.77	2.03
2029	6.21	11.50	7.53	0.66	2.12
2030	6.22	11.47	7.53	0.55	2.22
2031	6.23	11.45	7.54	0.55	2.38
2032	6.23	11.41	7.53	0.55	2.55
2033	6.24	11.38	7.52	0.55	2.72
2034	6.23	11.33	7.51	0.55	2.89
2035	6.35	11.43	7.62	0.55	3.06
2036	6.38	11.42	7.64	0.55	3.22
2037	6.47	11.49	7.72	0.55	3.39
2038	6.54	11.53	7.78	0.55	3.56
2039	6.58	11.54	7.82	0.55	3.73
2040	6.63	11.56	7.86	0.55	3.89
2041	6.71	11.62	7.93	0.55	4.06
2042	6.77	11.65	7.99	0.55	4.23
2043	6.85	11.71	8.07	0.55	4.40
2044	6.93	11.76	8.14	0.55	4.57
2045	7.00	11.82	8.21	0.55	4.73
2046	7.08	11.87	8.28	0.55	4.73
2047	7.21	11.99	8.41	0.55	4.73
2048	7.32	12.07	8.51	0.55	4.73
2049	7.45	12.19	8.64	0.55	4.73
2050	7.55	12.27	8.73	0.55	4.73
2051	7.64	12.35	8.82	0.55	4.73
2052	7.74	12.43	8.91	0.55	4.73
2053	7.84	12.51	9.01	0.55	4.73
2054	7.95	12.60	9.11	0.55	4.73
2055	8.05	12.69	9.21	0.55	4.73
2056	8.16	12.78	9.31	0.55	4.73
2057	8.26	12.87	9.42	0.55	4.73

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Electric Avoided Costs – EE Programs (2018$)

Year	Energy $/kWh	Capacity $/kW-yr	T&D $/kW-yr	DRIPE $/kWh	CO2 $/kWh	Total Energy $/kWh
2019	$ 0.0494	$ 49.7354	$ 35.3291	$ -	$ -	$ 0.0494
2020	$ 0.0497	$ 49.7355	$ 35.3304	$ 0.0158	$ -	$ 0.0656
2021	$ 0.0503	$ 49.7399	$ 35.3304	$ 0.0216	$ -	$ 0.0718
2022	$ 0.0506	$ 49.7377	$ 35.3288	$ 0.0264	$ 0.0228	$ 0.0998
2023	$ 0.0508	$ 49.7392	$ 35.3255	$ 0.0301	$ 0.0243	$ 0.1052
2024	$ 0.0505	$ 49.7439	$ 35.3304	$ 0.0311	$ 0.0258	$ 0.1074
2025	$ 0.0579	$ 49.7413	$ 35.3330	$ 0.0372	$ 0.0273	$ 0.1224
2026	$ 0.0598	$ 49.7414	$ 35.3284	$ 0.0373	$ 0.0288	$ 0.1259
2027	$ 0.0651	$ 49.7435	$ 35.3262	$ 0.0355	$ 0.0302	$ 0.1309
2028	$ 0.0716	$ 49.7381	$ 35.3261	$ 0.0307	$ 0.0317	$ 0.1341
2029	$ 0.0751	$ 49.7434	$ 35.3277	$ 0.0242	$ 0.0332	$ 0.1326
2030	$ 0.0785	$ 49.7406	$ 35.3308	$ 0.0211	$ 0.0347	$ 0.1343
2031	$ 0.0794	$ 49.7387	$ 35.3305	$ 0.0174	$ 0.0373	$ 0.1341
2032	$ 0.0785	$ 49.7374	$ 35.3313	$ 0.0134	$ 0.0400	$ 0.1318
2033	$ 0.0767	$ 49.7362	$ 35.3286	$ 0.0094	$ 0.0426	$ 0.1287
2034	$ 0.0772	$ 49.7431	$ 35.3307	$ 0.0018	$ 0.0452	$ 0.1242
2035	$ 0.0776	$ 49.7412	$ 35.3289	$ 0.0018	$ 0.0479	$ 0.1272
2036	$ 0.0784	$ 49.7385	$ 35.3313	$ 0.0018	$ 0.0505	$ 0.1307
2037	$ 0.0793	$ 49.7427	$ 35.3295	$ 0.0018	$ 0.0531	$ 0.1342
2038	$ 0.0802	$ 49.7377	$ 35.3274	$ 0.0018	$ 0.0557	$ 0.1377
2039	$ 0.0816	$ 49.7388	$ 35.3286	$ 0.0018	$ 0.0584	$ 0.1418
2040	$ 0.0816	$ 49.7379	$ 35.3327	$ 0.0018	$ 0.0610	$ 0.1444
2041	$ 0.0816	$ 49.7421	$ 35.3283	$ 0.0018	$ 0.0636	$ 0.1470
2042	$ 0.0816	$ 49.7366	$ 35.3301	$ 0.0018	$ 0.0663	$ 0.1496
2043	$ 0.0816	$ 49.7425	$ 35.3304	$ 0.0018	$ 0.0689	$ 0.1523
2044	$ 0.0816	$ 49.7384	$ 35.3292	$ 0.0018	$ 0.0715	$ 0.1549
2045	$ 0.0816	$ 49.7379	$ 35.3296	$ 0.0018	$ 0.0741	$ 0.1575

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Electric Avoided Costs – CHP Program (2018$)

Year	Energy $/kWh	Capacity $/kW-yr	T&D $/kW-yr	DRIPE $/kWh	CO2 $/kWh	Total Energy $/kWh
2019	$ 0.0486	$ 48.9503	$ 34.7714	$ -	$ -	$ 0.0486
2020	$ 0.0489	$ 48.9504	$ 34.7727	$ 0.0156	$ -	$ 0.0645
2021	$ 0.0495	$ 48.9547	$ 34.7727	$ 0.0212	$ -	$ 0.0707
2022	$ 0.0498	$ 48.9526	$ 34.7711	$ 0.0260	$ 0.0225	$ 0.0982
2023	$ 0.0499	$ 48.9541	$ 34.7679	$ 0.0296	$ 0.0239	$ 0.1035
2024	$ 0.0497	$ 48.9586	$ 34.7727	$ 0.0306	$ 0.0254	$ 0.1057
2025	$ 0.0570	$ 48.9561	$ 34.7752	$ 0.0366	$ 0.0268	$ 0.1205
2026	$ 0.0589	$ 48.9562	$ 34.7707	$ 0.0367	$ 0.0283	$ 0.1239
2027	$ 0.0641	$ 48.9583	$ 34.7685	$ 0.0349	$ 0.0298	$ 0.1288
2028	$ 0.0705	$ 48.9529	$ 34.7684	$ 0.0302	$ 0.0312	$ 0.1319
2029	$ 0.0739	$ 48.9581	$ 34.7700	$ 0.0239	$ 0.0327	$ 0.1305
2030	$ 0.0772	$ 48.9554	$ 34.7730	$ 0.0208	$ 0.0342	$ 0.1322
2031	$ 0.0781	$ 48.9536	$ 34.7728	$ 0.0171	$ 0.0368	$ 0.1320
2032	$ 0.0772	$ 48.9522	$ 34.7736	$ 0.0132	$ 0.0393	$ 0.1298
2033	$ 0.0755	$ 48.9510	$ 34.7709	$ 0.0092	$ 0.0419	$ 0.1267
2034	$ 0.0760	$ 48.9579	$ 34.7730	$ 0.0018	$ 0.0445	$ 0.1222
2035	$ 0.0763	$ 48.9560	$ 34.7712	$ 0.0018	$ 0.0471	$ 0.1252
2036	$ 0.0772	$ 48.9534	$ 34.7736	$ 0.0018	$ 0.0497	$ 0.1286
2037	$ 0.0781	$ 48.9575	$ 34.7718	$ 0.0018	$ 0.0523	$ 0.1321
2038	$ 0.0789	$ 48.9526	$ 34.7697	$ 0.0018	$ 0.0549	$ 0.1355
2039	$ 0.0803	$ 48.9536	$ 34.7709	$ 0.0018	$ 0.0574	$ 0.1395
2040	$ 0.0803	$ 48.9527	$ 34.7749	$ 0.0018	$ 0.0600	$ 0.1421
2041	$ 0.0803	$ 48.9569	$ 34.7706	$ 0.0018	$ 0.0626	$ 0.1447
2042	$ 0.0803	$ 48.9514	$ 34.7724	$ 0.0018	$ 0.0652	$ 0.1473
2043	$ 0.0803	$ 48.9573	$ 34.7727	$ 0.0018	$ 0.0678	$ 0.1499
2044	$ 0.0803	$ 48.9532	$ 34.7715	$ 0.0018	$ 0.0704	$ 0.1525
2045	$ 0.0803	$ 48.9527	$ 34.7719	$ 0.0018	$ 0.0730	$ 0.1550

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3.2 Detailed Program and Portfolio Cost-effectiveness

Energy Efficiency Programs' Cost-effectiveness over Five-Year Portfolio (2018$)

	Total Resource					Gas Energy System				
	Present Value		PV of Net	Benefit-Cost	Levelized Cost	Present Value		PV of Net	Benefit-Cost	Levelized Cost
	Benefit	Cost	Benefits	Ratio	$/MMBTU	Benefit	Cost	Benefits	Ratio	$/MCF
	[2]	[3]	[4]	[5]		[10]	[11]	[12]	[13]	
Portfolio Total	$135,067,931	$75,053,822	$60,014,109	1.80	6.07	$128,896,731	$47,639,648	$81,257,083	2.71	3.85
Non-Measure Costs		$13,832,162					$13,832,162			
Total Measure Costs	$134,411,269	$61,221,660	$73,189,608	2.20	4.95	$128,896,731	$33,807,486	$95,089,245	3.81	2.74
Program										
Residential Prescriptive (RP)										
Program Total	$66,906,943	$36,799,435	$30,107,508	1.82	5.79	$66,740,097	$22,995,133	$43,744,963	2.90	3.62
Non-Measure Costs		$1,623,960					$1,623,960			
Total Measure Costs	$66,906,943	$35,175,475	$31,731,468	1.90	5.54	$66,740,097	$21,371,174	$45,368,923	3.12	3.36
Residential New Construction (RNC)										
Program Total	$7,986,156	$3,786,306	$4,199,851	2.11	5.91	$4,951,531	$2,494,428	$2,457,103	1.99	3.90
Non-Measure Costs		$909,030					$909,030			
Total Measure Costs	$7,986,156	$2,877,276	$5,108,881	2.78	4.49	$4,951,531	$1,585,398	$3,366,133	3.12	2.48
Residential Retrofit (RR)										
Program Total	$11,876,481	$10,010,434	$1,866,047	1.19	9.82	$11,073,033	$9,311,785	$1,761,248	1.19	9.13
Non-Measure Costs		$5,204,849					$5,204,849			
Total Measure Costs	$11,876,481	$4,805,585	$7,070,896	2.47	4.71	$11,073,033	$4,106,936	$6,966,097	2.70	4.03
Nonresidential Prescriptive (NP)										
Program Total	$30,824,692	$8,147,406	$22,677,285	3.78	2.86	$29,572,845	$3,827,949	$25,744,895	7.73	1.34
Non-Measure Costs		$624,609					$624,609			
Total Measure Costs	$30,824,692	$7,522,798	$23,301,894	4.10	2.64	$29,572,845	$3,203,340	$26,369,504	9.23	1.12
Nonresidential Custom (NC)										
Program Total	$16,816,997	$12,415,806	$4,401,191	1.35	8.30	$16,559,226	$5,115,917	$11,443,309	3.24	3.42
Non-Measure Costs		$1,575,279					$1,575,279			
Total Measure Costs	$16,816,997	$10,840,527	$5,976,470	1.55	7.25	$16,559,226	$3,540,638	$13,018,589	4.68	2.37
Portfoliowide Costs										
Program Total	-	$3,511,529	$(3,511,529)	-	-	-	$3,511,529	$(3,511,529)	-	-
Non-Measure Costs		$3,511,529					$3,511,529			
Total Measure Costs	-	-	-	-	-	-	-	-	-	-
LIURP Transfer										
Program Total	$656,663	$382,906	$273,756	1.71	#DIV/0!	-	$382,906	$(382,906)	-	#DIV/0!
Non-Measure		$382,906					$382,906			

Energy Efficiency Programs’ Cost-effectiveness over Five-Year Portfolio (2018$), including DRIPE & CO_2

	Total Resource					Gas Energy System				
	Present Value		PV of Net	Benefit-Cost	Levelized Cost	Present Value		PV of Net	Benefit-Cost	Levelized Cost
	Benefit [2]	Cost [3]	Benefits [4]	Ratio [5]	$/MMBTU	Benefit [10]	Cost [11]	Benefits [12]	Ratio [13]	$/MCF
Portfolio Total	$172,408,745	$75,053,822	$97,354,923	2.30	6.07	$166,058,599	$47,639,648	$118,418,950	3.49	3.85
Non-Measure Costs		$13,832,162					$13,832,162			
Total Measure Costs	$171,573,136	$61,221,660	$110,351,476	2.80	4.95	$166,058,599	$33,807,486	$132,251,112	4.91	2.74
Program										
Residential Prescriptive (RP)										
Program Total	$86,025,637	$36,799,435	$49,226,202	2.34	5.79	$85,858,791	$22,995,133	$62,863,658	3.73	3.62
Non-Measure Costs		$1,623,960					$1,623,960			
Total Measure Costs	$86,025,637	$35,175,475	$50,850,162	2.45	5.54	$85,858,791	$21,371,174	$64,487,617	4.02	3.36
Residential New Construction (RNC)										
Program Total	$9,477,571	$3,786,306	$5,691,266	2.50	5.91	$6,442,946	$2,494,428	$3,948,518	2.58	3.90
Non-Measure Costs		$909,030					$909,030			
Total Measure Costs	$9,477,571	$2,877,276	$6,600,295	3.29	4.49	$6,442,946	$1,585,398	$4,857,547	4.06	2.48
Residential Retrofit (RR)										
Program Total	$14,911,896	$10,010,434	$4,901,462	1.49	9.82	$14,108,448	$9,311,785	$4,796,663	1.52	9.13
Non-Measure Costs		$5,204,849					$5,204,849			
Total Measure Costs	$14,911,896	$4,805,585	$10,106,311	3.10	4.71	$14,108,448	$4,106,936	$10,001,512	3.44	4.03
Nonresidential Prescriptive (NP)										
Program Total	$39,700,986	$8,147,406	$31,553,580	4.87	2.86	$38,449,139	$3,827,949	$34,621,190	10.04	1.34
Non-Measure Costs		$624,609					$624,609			
Total Measure Costs	$39,700,986	$7,522,798	$32,178,189	5.28	2.64	$38,449,139	$3,203,340	$35,245,799	12.00	1.12
Nonresidential Custom (NC)										
Program Total	$21,457,045	$12,415,806	$9,041,239	1.73	8.30	$21,199,275	$5,115,917	$16,083,357	4.14	3.42
Non-Measure Costs		$1,575,279					$1,575,279			
Total Measure Costs	$21,457,045	$10,840,527	$10,616,519	1.98	7.25	$21,199,275	$3,540,638	$17,658,637	5.99	2.37
Portfoliowide Costs										
Program Total	-	$3,511,529	$(3,511,529)	-	-	-	$3,511,529	$(3,511,529)	-	-
Non-Measure Costs		$3,511,529					$3,511,529			
Total Measure Costs	-	-	-	-	-	-	-	-	-	-
LIURP Transfer										
Program Total	$835,609	$382,906	$452,703	2.18	#DIV/0!	-	$382,906	$(382,906)	-	#DIV/0!
Non-Measure		$382,906					$382,906			

CHP Program Cost-effectiveness over Five-Year Portfolio (2018$)

PV 2018$	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	Total
TRC Benefits	$23,045,224	$22,498,360	$21,990,378	$21,519,254	$24,660,447	**$113,713,664**
TRC Costs	19,651,609	18,637,072	17,674,951	16,762,536	19,272,066	**91,998,234**
Utility Costs	635,000	635,000	635,000	635,000	902,500	**3,442,500**
TRC Net Benefits	**$3,393,615**	**$3,861,288**	**$4,315,427**	**$4,756,718**	**$5,388,382**	**$21,715,430**
TRC BCR	1.17	1.21	1.24	1.28	1.28	1.24

CHP Program Cost-effectiveness over Five-Year Portfolio (2018$), including DRIPE and CO_2

PV 2018$	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	Total
TRC Benefits	$42,036,884	$41,636,153	$41,074,702	$39,733,123	$44,803,852	**$209,284,714**
TRC Costs	19,651,609	18,637,072	17,674,951	16,762,536	19,272,066	**91,998,234**
Utility Costs	635,000	635,000	635,000	635,000	902,500	**3,442,500**
TRC Net Benefits	**$22,385,275**	**$22,999,081**	**$23,399,751**	**$22,970,587**	**$25,531,786**	**$117,286,481**
TRC BCR	2.14	2.23	2.32	2.37	2.32	2.27