BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF QUESTAR GAS COMPANY TO INCREASE DISTRIBUTION RATES AND CHARGES AND MAKE TARIFF MODIFICATIONS	Docket No. 16-057-03

DIRECT TESTIMONY OF

KELLY B MENDENHALL FOR

QUESTAR GAS COMPANY

July 1, 2016

QGC Exhibit 3.0

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I. INTRODUCTION

Q. Please state your name and business address.

A. Kelly B Mendenhall, 333 South State Street, Salt Lake City, Utah 84111.

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

A. I am employed by Questar Gas Company (Questar Gas or Company) as the General Manager of Regulatory Affairs. My qualifications are detailed in QGC Exhibit 3.1.

Q. Were the attached Exhibits 3.1 – 3.31 prepared by you or under your direction?

A. The inflation factors shown in QGC Exhibit 3.13 were prepared by Global Insight. All other exhibits were prepared under my direction.

Q. What general areas will your testimony address?

A. My testimony will explain why the proposed test period of the average 12 months ending December 2017 best reflects the conditions that will exist during the rate-effective period. I will also calculate the proposed revenue requirement and deficiency resulting from the December 2017 test period.

II. BASE AND TEST PERIODS

Q. What base period is the Company proposing in this case?

A. The Company proposes the base period to be the 12-month period ending December 31, 2015.

Q. What test period is the Company proposing in this case?

A. The Company proposes the test period to be the average 12-month period that will end on December 31, 2017 with all elements of the test period based on 2017 forecasts. As I will discuss later, this test period coincides with and reflects the conditions that will exist during the rate-effective period beginning in March 2017.

Q. Is the proposed test period consistent with the Commission's test period requirements found in Section 54-4-4 (3) (a) of the Utah Public Utility Code?

A. Yes. Section 54-4-4(3)(a) provides that, "the Commission shall select a test period that, on the basis of evidence, the Commission finds best reflects conditions that a public utility will encounter during the period when the rates determined by the Commission will be in effect." The Commission may use a future test period that is determined on the basis of projected data not exceeding 20 months from the date a proposed rate increase or decrease is filed. In this case, the Company is proposing to use a future test period that is based on 18 months of projected data from the July 1, 2016 filing date.

Q. Is this test period consistent with the methodology the Company used in the last General Rate Case?

A. Yes. In Docket No. 13-057-05 filed on July 1, 2013, the Company used an 18 month projected test period. This test period was not contested and was ultimately approved by the Utah Public Service Commission (Commission).

Q. How does the 2017 test period compare with the rate effective-period?

A. The rate-effective period will begin March 1, 2017. It is unknown when the rate effective period will end, but if history is any indication, the rate effective period could extend into 2020. The Company's proposed future test period, using average-year data, is a better reflection of the conditions Questar Gas will encounter during this rate effective period than a 2015 or 2016 test period. This test period reflects expenses and investment projected from January 2017 through December 2017. The average 2017 test period best reflects the conditions that will occur while rates are in effect.

Q. What are the major drivers of this proposed rate increase?

A. As Mr. McKay explained, the major driver of the increase in rates requested in this case is the Company's significant increase in capital investment. The projected net plant for 2017 is over $400 million higher than the approved net plant in the last general rate case. Depreciation expense, taxes and return on rate base have increased due to the large amount of capital spending in the last three years. Including 2016 and 2017, the Company will have invested over $600 million since the last rate case. This capital investment was used for customer growth, aging infrastructure replacement and system expansion. This significant increase in investment makes it more important than ever to correctly match the test period with the rate effective period.

Q. Do you think the synchronization of investment, revenues and expenses is an important factor to consider?

A. Yes, synchronization is an essential part of creating an accurate forecast. There is a direct link between the number of customers, revenue and investment. As the number of customers rises, so does investment and the corresponding revenue from those customers. Depreciation expense, property taxes and deferred income taxes are also linked to investment. All of these items have been tied together to develop a test period that best reflects the conditions that will occur during the rate-effective period.

Q. How have you synchronized the rate base, expenses and revenues?

A. I projected investment and other rate base accounts for 2016 and 2017. I adjusted the depreciation expense, property taxes and deferred income taxes to match the investment. I included the capital expenditures related to new customer growth in the 2016 and 2017 investment amounts. I also included incremental revenue and volumes from new customer growth in the revenue forecasts for 2016 and 2017.

Q. What is the general approach you have taken to develop the 2017 test period and revenue requirement?

A. The foundation for the December 2017 test period is the Company's historical financial information for the 12 months ended December 2015 as filed in the Company's last results of operations report. These amounts can be found on column B of QGC Exhibit 3.2. I made adjustments to expenses, rate base and revenues to reflect the amounts anticipated to be in effect on December 31, 2017 (Section II A. – Section II E. below). I then applied regulatory adjustments required in past rate cases to these 2017 forecasted numbers (Section III "Regulatory Adjustments" below). The total of these forecasting and regulatory adjustments is summarized on column C of QGC Exhibit 3.2. Column D presents the imputed tax adjustment. Columns B, C and D are added together to calculate the adjusted system total in column E. Finally, the numbers are allocated to the Utah and Wyoming jurisdictions. The Utah jurisdictional numbers are shown in column F.

Q. Please explain the adjustments you have made to revenue, expense, and rate base accounts that you expect to occur and have included in the December 2017 test-period values.

A. QGC Exhibit 3.2, column C, provides the total of all material changes in the test period from December 2015. QGC Exhibit 3.3 provides a summary of the changes in revenue, expenses and rate base by adjustment and show how these adjustments add up to the total shown on column C of QGC Exhibit 3.2. QGC Exhibits 3.4 through 3.28 provide a detailed calculation of each adjustment. I will provide a reference of where each adjustment can be found in the summary QGC Exhibit 3.3 and I will discuss the detail of each adjustment.

A. Rate Base

QGC Exhibit 3.3, column A and QGC Exhibit 3.4.

Q. Please explain how rate base was projected for the test period.

A. I calculated the projected Gas Plant in Service (Accounts 101/106) balances starting with actual December 2015 balances (QGC Exhibit 3.4, column A), as this is the most recently available historical data. I then added the net 2016 capital additions (column B) to calculate the projected December 2016 balance (column C). I added the 2017 net additions (column D) to the December 2016 balance to calculate the December 2017 balance (column E). QGC Exhibit 3.5 page 1 shows the calculation of the net additions for 2016. I took the $240 million capital budget by FERC account for 2016 (QGC Exhibit 3.5, page 1, column A) and I removed the vintage retirements expected to occur during 2016 (column B). Last, I added the amounts in the Construction Work in Progress (Account 107) and Completed Construction Not Classified (Account 106) at the end of 2015 that will be closed in 2016 (column C) and removed the 2016 expenditures expected to be in Construction Work in Progress at the end of the year (column D). I then added the net 2016 additions in column E to the 2015 plant balances by FERC account to arrive at a December 2016 balance. I completed this step in the rate case model in the 101-106 Projection tab. I took the same steps in QGC Exhibit 3.5, page 2, columns F through J to arrive at December 31, 2017, Gas Plant in Service balances.

As I explained earlier, the main driver for the increase requested in this case is capital investment. The capital budget includes $240 million in 2016 and $209 million in 2017. As Mr. McKay explains, the Company is proposing to include $70.9 million in 2016 and $64.0 million in 2017 for the Infrastructure Rate Adjustment Mechanism (Tracker) for high pressure feeder lines and intermediate high pressure pipeline replacements, which represents over 30 percent of the capital budget. While these replacements are necessary for the integrity and safety of the system, they do not directly add any additional revenue.

Questar Gas has also projected the Accumulated Depreciation/Amortization (Accounts 108, 111 and 254) will increase by $97 million from December 2015 to December 2017 resulting in an ending balance of $977 million for the test year (QGC Exhibit 3.6, column E, line 14). Account 254 – Other Regulatory Liabilities has amounts associated with depreciation expense of future removal costs and will change as assets are depreciated. Future removal costs are part of the overall depreciation calculation, so the combination of the changes of Accounts 108 and 254 will reflect the total depreciation expense each year, similar to the total change in Account 108 prior to this accounting change.

I calculated the Miscellaneous Customer Credits (Account 252) by taking the historical balances and projecting contributions received, customer refunds, and cancellations of expired agreements. (QGC Exhibit 3.7).

The Materials and Supplies balances (Account 154), Prepayments (Account 165), Customer Deposits (Account 235), and Unclaimed Customer Deposits (Account 253.1) are seasonal in nature. I used actual balances through March 2016. Starting with April 2016, I forecasted the seasonal fluctuations using the historical trends from 2015.

The deferred income tax credits (Account 255) is a straight-line amortization that can be easily forecasted. (QGC Exhibit 3.8, line 6).

I calculated the deferred income taxes account balances (Account 282) for 2016 and 2017 by taking projected investment, depreciation and tax amounts and projecting their impact on deferred income taxes. (QGC Exhibit 3.8, line 5).

Q. Will you make any adjustments to the accumulated deferred income tax component of rate base?

A. Possibly. The Company is currently analyzing certain U.S. Treasury Department tax normalization rules to ensure that its proration methodology in this case is appropriate.

Q. Does the Company anticipate that a methodology change would have significant impact on revenue requirement?

A. Our analysis to date suggests that any change would be minimal. However, the Company would like to ensure that its methodology is compliant with these rules. We will update the revenue requirement calculation, if necessary.

Q. You stated that you used the Capital Budget to forecast the plant for the year ended December 2017. How accurate have the Company's capital budget forecasts been in the past?

A. QGC Exhibit 3.9 shows the capital budget for the last five years compared to actual expenditures. As shown on line 6 of the exhibit, the Company spends about 97% of budget amounts on average.

B. Forecasted Expenses

QGC Exhibit 3.3, column B and QGC Exhibit 3.10.

Q. What is the Company projecting for test period operating and maintenance (O&M) expense?

A. A summary of 2015 base period expenses, as well as forecasted 2016 and 2017 expenses are shown in QGC Exhibit 3.10. As page 1, column C, line 52, shows, the Company is projecting 2017 O&M expenses of $170.2 million.

Q. What approach did you use to adjust historical O&M expenses to reflect the forecasted test period O&M expenses?

A. I forecasted the two major components that make up operating and maintenance expenses, labor and non-labor, using different methods. It was necessary to identify the historical labor and non-labor expenses by FERC account and split them out. QGC Exhibit 3.10, page 2 shows test period expenses separated by FERC account and cost component. Labor and labor overhead makes up about $79.2 million of the total O&M expense (QGC Exhibit 3.10, page 2, column A, line 52). All other O&M expenses were included in the non-labor category (column B).

Q. How did you forecast the labor and labor overhead O&M expenses?

A. Detailed monthly amounts are shown in QGC Exhibit 3.11. I used historical labor and labor overhead amounts through March 2016 (Page 1, columns B through D). I then used amounts taken from the 2016 forecast for the remainder of 2016 for an increase of 2.9%. I calculated 2017 annual expenses by taking the December 2016 amounts and inflating them by 3% (QGC Exhibit 3.11, page 2).

Q. How did you forecast the non-labor O&M expenses?

A. The detailed calculation is shown in QGC Exhibit 3.12. The basis for the forecasted non-labor O&M expenses was the O&M expenses from April 2015 through March 2016, as this was the most current historical data that was available. As column C of the exhibit shows, I increased or decreased the historical expenses from April through December of 2015 using the 2016 inflation factors from the Global Insight Power Planner report. QGC Exhibit 3.13 includes the pages from this report used in the forecast. I summed the historical expenses from January through March of 2016 (column B) and the projected expenses from April through December of 2016 (column C) together in column D to calculate the total 2016 expenses. I then increased or decreased these 2016 expenses using the Global Insight inflation factors for 2017 (see QGC Exhibit 3.13) to calculate the total 2017 expenses (column E).

Q. How accurate have the Company's O&M budgets been in the past?

A. QGC Exhibit 3.9 shows a comparison of historical actual O&M expenses compared to budget expenses. Line 12 of the exhibit shows that on average over the last 5 years, the Company was within 1% of its projected budget amounts.

C. Revenue

QGC Exhibit 3.3, column C and QGC Exhibit 3.15

Q. How have you estimated usage per customer for the test period?

A. The long-term trend of usage per customer has been declining over the last few decades. QGC Exhibit 3.14 shows the historical and forecasted use per customer for the GS class in Utah. As shown on the graph, the GS class experienced a decline in 2015 and this decline is expected to continue through 2017. The table below shows the projected usage per customer for 2016 and 2017.

	Usage Per Customer	Change From Prior Year
Historical 12 Months Ended December 2015	105.48	
Projected 12 Months Ended December 2016	104.22	-1.26
Projected 12 Months Ended December 2017	102.91	-1.31

The projected usage per customer is 104.2 Dth in 2016 and 102.9 in 2017. The forecast was developed using statistical time series methods on the monthly historical usage through the year 2015.

Q. How have you estimated customers for the test period?

A. The estimated customer totals used in this case for the remainder of 2016 and all of 2017 are based on the Company's most recent Integrated Resource Plan filed June 14, 2016. In 2015 the Company experienced high growth in Utah additions. This trend is expected to continue for both the residential and commercial construction sectors. The projections show that 20,243 customers will be added in 2016 and 20,486 will be added in 2017.

Q. How did you calculate revenues for the test period?

A. Revenues for all rate classes were based on projected customer numbers and expected volumetric annual usage. QGC Exhibit 3.15 shows the revenue detail for 2017. I projected revenues through December 2017 using anticipated customers and usage.

D. Depreciation Expense

QGC Exhibit 3.3, column B and QGC Exhibit 3.16.

Q. Please explain the depreciation adjustment.

A. A summary of the adjustment is shown in QGC Exhibit 3.16. The Commission-approved depreciation rates are shown in column B and the annual depreciation amounts are shown in column C. The detailed calculation of this tab is shown in the 108_111 Projection tab of QGC Exhibit 4.16 Utah Rate Case Model.xls. I removed the amounts related to the reserve variance and clearing from expense in lines 75, 141 and 142. The overall result is a proposed depreciation expense of $70.1 million as shown on column C, line 149. This is a $15 million increase for 2015 levels.

Q. Are there proposed changes to the depreciation rates in this case?

A. No. In the Revenue Requirement Stipulation in Docket No. 07-057-13, the Company agreed to perform a new depreciation study every five years on a going-forward basis. The last study was performed by the third party depreciation consultant Gannett Fleming in 2013 and approved in Docket 13-057-19. The Company anticipates that the next study will be completed in 2018. The depreciation rates approved in Docket 13-057-19 will remain in effect through the test period.

E. Taxes Other than Income Taxes

QGC Exhibit 3.3, column B and QGC Exhibit 3.17.

Q. How did the Company forecast taxes other than Income Taxes?

A. The detail is shown in QGC Exhibit 3.17. Total other taxes for 2017 are expected to be about $3.7 million higher than the 2015 period amounts due mainly to an increase in property taxes (line 1). Questar Gas' assessed property valuation has increased due to increased capital additions. This adjustment is included as part of the forecasted expense adjustment and can be seen on QGC Exhibit 3.3, column B, line 26.

III. REGULATORY ADJUSTMENTS

A. Underground Storage

QGC Exhibit 3.3, column D and QGC Exhibit 3.18.

Q. Please explain the adjustment for Gas Stored Underground.

A. Pursuant to the final order in Docket No. 93-057-01, Account 164, Gas Stored Underground - Current, is to be accounted for in the Company's pass-through cases and excluded from test-year rate base. This is accomplished in the pass-through cases by allowing a return on the actual average balance in this account to be entered as a gas cost in the 191 Account. This adjustment removes the total balance of Account 164 from the rate-base calculation.

B. Wexpro Adjustment to Production Plant

QGC Exhibit 3.3, column E and QGC Exhibit 3.19.

Q. Please explain the adjustment for Wexpro investment.

A. In accordance with the Wexpro Agreement, Wexpro adds 6.3% of Questar Gas' production plant to the Wexpro investment as a general plant allowance when calculating the Wexpro service fee charged to Questar Gas. The Wexpro Agreement also provides that the production plant component in each Questar Gas rate base plant account be reduced by 6.3**%.**

C. Bad Debt Expense

QGC Exhibit 3.3, column F and QGC Exhibit 3.20.

Q. What is the adjustment for bad-debt expense?

A. Bad debt expense is broken out into three components: bad debt related to distribution non-gas revenue, bad debt related to supplier non-gas revenue and bad debt related to commodity revenue. This adjustment first removes the bad debt related to supplier non-gas on line 7

($272,743) and commodity revenue on line 8 ($1,088,832) because as they are accounted for in the pass through. Next, the adjustment annualizes the DNG portion of bad-debt expense forecasted to occur for the 12 months ended December 2017 to the 3-year average level of bad-debt expense. The Division of Public Utilities (DPU) originally proposed this methodology in the 1995 general rate case and it has been used in Docket Nos. 99-057-20, 02-057-02, 07-057-13, 09-057-16 and 13-057-05. The calculation of this adjustment is shown on QGC Exhibit 3.20, lines 19 through 24. I divided net charge-offs for each year (line 20) by booked system revenues (line 19) to calculate a bad-debt ratio (line 22). I calculated the ratios of 0.17%, 0.18% and 0.20% for 2013, 2014 and 2015, respectively, and calculated the three-year average of 0.18% in column I, line 24. I calculated the allowed DNG related bad debt in column H, lines 26-38. I multiplied Test-Period Utah Distribution Non-Gas revenue of $371,106,729 (line 26) by the adjusted three-year average of 0.18% (line 28) to calculate an allowed Utah DNG bad debt of $669,690 (line 29). The base-period system Utah DNG bad-debt expense is $763,329 (line 32). The base-period bad debt expense is based on 2015 bad debt. Because the three year bad debt average is lower than the 2015 percentage, the resulting adjustment is a decrease to Utah expenses of ($93,639) (line 36).

D. Incentive Compensation

QGC Exhibit 3.3, column G and QGC Exhibit 3.21, pages 1–4.

Q. Please explain the incentive-compensation adjustment.

A. In accordance with previous Commission orders in Docket Nos. 93-057-01, 95-057-02, 99-057-20 and 02-057-02 Questar Gas has removed, for ratemaking purposes, incentive-compensation expenses related to net-income, earnings-per-share and return-on-equity goals either paid directly by Questar Gas or allocated from Questar Corporation for incentive payouts. In these dockets, the Commission allowed incentives paid based on Questar Gas operating goals. These operating goals include reducing O&M per customer, increasing customer satisfaction and reducing accidents. This adjustment involves two steps. First, a weighted three-year average from 2013 to 2015 is calculated for the percentage of incentive payouts related to Questar Gas operating goals. As can be seen on page 4 of QGC Exhibit

3.21, the average payout related to Questar Gas operating goals was 50.6% for Questar Corporation's management plan (column D, line 6), 100% for Questar Corporation's employee plan (column C, line 14), 57.6% for Questar Gas' management plan (column D, line 22) and 100% for Questar Gas' employee plan (column C, line 30). I used 100% for the employee plan because the Company has gone to 100% operating goals for 2014, 2015 and 2016. I then multiplied these percentages by the incentive amounts forecasted to be paid out during the test period (QGC Exhibit 3.21, pages 2 and 3) In addition to the management- and employee-incentive plans, Questar Corporation has a long-term incentive plan that it pays to corporate officers. The $2.4 million related to this incentive plan has been removed on QGC Exhibit 3.21, page 2, column D, line 5. The end result of these adjustments is a removal of $2.95 million (QGC Exhibit 3.21, page 1, column A, line 3).

E. Sporting Events

QGC Exhibit 3.3, column H and QGC Exhibit 3.22.

Q. Please explain the adjustment for sporting events.

A. During the 2015 athletic season, Questar Gas received allocated expenses from Questar Corporation for tickets to sporting events at the Vivint Arena, Smith's Ball Park, and the Maverick Center. During this period, 47% of the tickets were used in a Questar Gas employee-recognition plan. That is, those employees who had performed in an exemplary manner were awarded tickets to the games. The remaining tickets were used for marketing or other purposes. Pursuant to Commission orders in Docket Nos. 99-057-20, 02-057-02, 07-057-13, 09-057- and 13-057-13, the portion of these expenses related to employee recognition is allowed in rates and the expenses related to marketing or other purposes are removed from rates. In the base period, $31,802 was associated with disallowed expenses. I adjusted this amount for inflation and removed $32,344 from the December 2017 results in QGC Exhibit 3.22, page 1 line 19.

F. Advertising

QGC Exhibit 3.3, column I and QGC Exhibit 3.23.

Q. Please explain the adjustment for advertising.

A. Consistent with the Commission order in Docket No. 93-057-01, and in general rate cases since 1993, an adjustment has been made to decrease expenses in the test period by removing the advertising expenses related to promotional and institutional advertising and the Parade of Homes. I have updated the base year amounts through March 2016, adjusted them for inflation and removed $4,605 from the December 2017 results in QGC Exhibit 3.23, page 1, line 14.

G. Donations and Memberships

QGC Exhibit 3.3, column J and QGC Exhibit 3.24.

Q. Please explain the adjustment for donations and memberships.

A. In the order in Docket No. 93-057-01, the Commission prescribed which types of donations and memberships are recoverable in rates. This adjustment identifies and removes similar entries that are included in the test period, and the same types of expenses allocated from Questar Corporation. There were three types of costs removed in this adjustment: donations, lobbying labor and overhead from Questar Corporation, and expenses paid to consultants related to lobbying. QGC Exhibit 3.24, page 2, lines 2-3, were lobbying expenses paid by Questar Corporation during the base period. Questar Corporation government relations department labor, overhead and A&G expense are shown on lines 4 and 5. Included in this adjustment, on line 6, is a portion of the American Gas Association (AGA) dues that have been determined to be related to promotional advertising or lobbying. Page 3 of QGC Exhibit 3.24 shows the projected donations for Questar Gas. I updated these donations for inflation and removed them from expenses. QGC Exhibit 3.24, page 1, line 3 shows that $209,017 has been removed from the test period.

H. Reserve Accrual

QGC Exhibit 3.3, column K and QGC Exhibit 3.25.

Q. Please explain the reserve accrual.

A. The reserve accrual includes legal liabilities associated with the Company's self-insurance program. In Docket No. 07-057-13, the Commission approved a stipulation of the parties that the allowed reserve accrual amount to be based on the five-year average of actual payments made by the Company. Line 7 of QGC Exhibit 3.25 shows the five-year average and line 8 shows the actual accruals made, adjusted for inflation. The adjustment on line 9 subtracts expense of $328,779 from the 2017 results.

I. Pipeline Integrity Expense

QGC Exhibit 3.3, column B.

Q. Please provide the background on the pipeline-integrity expense.

A. On April 21, 2004, in Docket No. 04-057-03, Questar Gas filed with the Commission an application for a deferred accounting order authorizing it to establish an account for costs the Company would incur in order to remain in compliance with the new federal requirements of the Pipeline Safety Improvement Act of 2002, and the Final Rule regarding "Pipeline Integrity Management in High Consequence Areas." On June 24, 2004, the Commission approved the application and authorized Questar Gas to defer the incremental gas-transmission-line-safety-compliance costs incurred on or after January 1, 2004. Two years later, on June 1, 2006 in Docket No. 05-057-T01, the Commission approved the Settlement Stipulation that allowed Questar Gas to begin expensing $2 million per year to cover pipeline-integrity costs. In Docket Nos. 07-057-13, 09-057-16, and 13-057-05, the Commission approved continued recovery of transmission integrity management costs.

Q. Please explain what the distribution integrity management program (DIMP) costs are and how they are treated?

A. In Docket No. 09-057-16 the Commission-approved stipulation allowed for the deferral of the Company's distribution integrity management costs.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) and the Department of Transportation (DOT) have published a rule establishing integrity-management requirements for gas-distribution-pipeline systems. Like the Federal Pipeline Safety Regulations, this proposed rule requires operators of gas distribution pipelines to develop and implement integrity management programs. The purpose of these programs is to enhance safety by identifying and reducing pipeline-integrity risks. The integrity-management programs required by the proposal are similar to those currently required for gas-transmission pipelines, but tailored to reflect the differences in and among distribution systems. The final DIMP rule was published December 4, 2009 and became effective February 12, 2010. Like the 2002 Pipeline Safety Act, the distribution integrity management program was federally mandated and will result in incremental costs.

Q. What additional changes to the Pipeline Safety Rules are expected in the near future?

A. Earlier this year, PHMSA proposed a "Mega Rule"[1] that will increase the testing, record keeping and other requirements by pipeline operators. The rule also introduces the concept of "moderate consequence areas." At the time of this filing, PHMSA is seeking public comment related to the rule. It is possible that the rule could go into effect some time in 2018.

Q. Will the Mega Rule result in increased integrity management costs?

A. The Company anticipates that these pipeline integrity costs could increase. At this point however, the rule is not final and estimating the impact on costs is not possible. For purposes of this rate case, the Company is not attempting to make any adjustments for the Mega Rule.

Q. What is the Company proposing to do with the transmission and distribution integrity management program expenses on a going-forward basis?

A. Currently the Company is collecting $5,000,000 in current expenses and $1,970,481 for amortized amounts. These costs are currently included in Account 874. I adjusted this account for inflation in 2016 and 2017 by applying the global insight inflation factors of -1.2% and 2.5 % respectively. This adjustment is discussed in more detail in Section B of my testimony. The inflation adjustment is the only adjustment the Company is proposing to make to pipeline integrity expenses in this case. The current $5,000,000 level of spending for these programs is in line with historical levels. QGC Exhibit 3.28 shows the historical

[1] Department of Transportation, Pipeline and Hazardous Materials Safety Administration, 49 CFR Part 191 and 192, Docket No. PHMSA–2011-0023, RIN 2137-AE72.

pipeline integrity expenses. As line 22 of the table shows, over the past three years the annual costs have been between $4.5 million and $5.3 million.

Q. Does the Company propose to make any changes to the amortization amount?

A. Other than inflation, the Company proposes to make no changes to the amortization amount. As line 30 of QGC Exhibit 3.28 shows, the balance in the 182.3 account at the end of March 2016 is $5.5 million in the Pipeline Integrity account. The Company is proposing to amortize the total. The $1,970,481 amortization amount will allow the Company to draw this balance towards $0 over the next three years.

Q. What will be the accounting treatment if the Company does not incur the full amount of ongoing expenses in a given year?

A. To the extent that actual ongoing expenses are less than $5.06 million per year, the difference will continue to be credited to the deferred account. To the extent that actual ongoing expenses are greater than $5.06 million, the difference will continue to be debited to the deferred account.

Q. Please summarize the proposed pipeline integrity expenses going forward?

A. The table below summarizes the Company's proposal:

	Docket No. 13-057-01	**2016 Inflation Percentage**	**2017 Inflation Percentage**	**Current Proposal**
Pipeline Integrity Expense	$5,000,000	-1.2%	2.5%	$5,063,500
Amortization Amount	$1,970,481	-1.2%	2.5%	$1,995,506
Total	$6,970,481			$7,059,006

J. Removal of Energy Efficiency Expenses

QGC Exhibit 3.3, column L and QGC Exhibit 3.26

Q. Should energy efficiency expenses be removed?

A. Yes. The energy efficiency program revenues are collected from customers through the demand-side-management-amortization rate. When revenues are collected, an offsetting expense is made to the 908007 expense account. These revenues are not collected through distribution non-gas rates and are not included in the 2017 revrun calculation. Therefore, the energy efficiency expenses should also be removed. QGC Exhibit 3.26, line 13, shows the monthly entries and the removal of these expenses.

K. Lead-Lag Study

Q. In Docket No. 13-057-05, the Company used a Lead-Lag study based on 2010 data. Have you updated your Lead-Lag study in this case?

A. Yes. The Company is using an updated Lead-Lag study based on 2014 data. I have attached the updated study as QGC Exhibit 3.27. The Commission approved stipulation in Docket No. 07-057-13, requires the Company to use a lead-lag study in which the end date of the period used for the study is not more than three years old at the time of the filing. The end date of the 2014 study will be less than three years old at the time of this filing. The result of the study provides a net lag of 1.761 days, or an increase of about .75 days. The use of the study results in a test-year cash working capital requirement of $3.7 million (QGC Exhibit 3.2, column F, line 48).

Q. What caused the increase in lag days?

A. The increase is mainly due to property taxes, payroll taxes and longer revenue lag days. Property tax dollars made up 70% of all taxes other than income taxes in 2014 compared to 64% in 2010. Because the property taxes have 153 lag days and all of the other taxes have 32.5 days, merely increasing the dollars paid in property taxes drives the overall lag days up for this group. The revenue lag on royalty revenue increased by almost eleven days. The lag for federal payroll taxes (FICA and income taxes) was an average of 5.5 days longer in 2014 than it was in 2010.

Q. Please explain how the Lead-Lag study affects cash working capital.

A. Cash working capital is defined as the amount of cash needed on hand by a utility to pay its daily operating expenses for the period between the time it provides services to its customers and the time it receives payment for those services. If, on average, the time to collect revenues for services exceeds the time to pay the expenses for those services, the utility is experiencing a positive "net revenue lag" which requires cash on hand. If, on the other hand, the lag to pay expenses is longer than the lag to collect revenues, it is experiencing a negative "net revenue lag."

IV. PROJECTED DEFICIENCY AND REVENUE REQUIREMENT

Q. Have you calculated a total revenue requirement for this case?

A. Yes, based on the projected capital structure and a 9.85% return on equity incorporated together with the forecasted data and regulatory adjustments, I have calculated the total Utah revenue requirement to be approximately $361 million. (QGC Exhibit 3.2, column H, line 3).

Q. Using the projected volumetric revenue, what is the projected revenue deficiency for the test period?

A. QGC Exhibit 3.2 shows that for the proposed test period, the Utah operations of the Company would be expected to earn 7.91%. This results in a revenue deficiency of $22.2 million (column G, line 3).

Q. Have you made a similar calculation of the revenue deficiency using Commission-allowed revenues for the GS class instead of the volumetric revenue?

A. Yes. QGC Exhibit 3.29 shows that for the test year, the Utah operations of the Company would be expected to earn 8.49% return on common equity during the rate-effective period absent rate relief in this docket. This amounts to a revenue deficiency of $15.6 million.

Q. Does the difference cause the total revenue requirement to change?

A. No. The allowed revenue requirement does not change. A summary of the two calculations is shown in the table below:

	Current Revenue	Deficiency	Revenue Requirement
Volumetric Revenue	$338.9 Million	$22.2 Million	$361.2 Million
CET Allowed Revenue	$345.6 Million	$15.6 Million	$361.2 Million

Rates will be set on the total revenue requirement, not the deficiency, thus, the end results will be the same regardless of how one calculates revenue deficiency.

V. TRANSPORTATION IMBALANCE CHARGE

Q. What is the transportation imbalance charge?

A. The transportation imbalance charge is a rate assessed to transportation customers for upstream services they use on the Questar Gas system. The rate is assessed on daily imbalance volumes outside of a 5% tolerance. In the Order dated November 9, 2015 in Docket 15-057-31, the Commission approved a supplier non-gas charge of $0.08896 per decatherm applied to daily imbalance volumes outside of a 5 percent tolerance for transportation customers taking service under the MT, TS and FT-1 rate schedules. The rate effective date for the charge was February 1, 2016.

Q. Why is the Company providing additional information on the charge in this case?

A. On November 9, the Commission ordered that "This rate will be reviewed and evaluated in Questar's upcoming 2016 general rate case as well as in future 191 account pass-through filings to determine if the Imbalance Charge is achieving the intended objectives and whether changes should be implemented."(Order, Docket No. 14-057-31, paragraph IV.J., pages 37-38).

Q. Have you updated the transportation imbalance charge in this docket?

A. Yes. For informational purposes, the rate has been calculated using the data for the twelve months ended May, 2016. A comparison of the original rate calculation in Docket 14-057-31, the most recent pass through filing in Docket 16-057-06 and this docket is shown in QGC Exhibit 3.30.

Q. Are you asking that this rate be approved by the Commission?

A. No. The Company will be updating this rate in the next pass-through filing, based on then-current data and the Commission's decision in that docket will likely be effective before this docket is complete.

Q. The intent of the charge was to encourage customers to make more accurate nominations and to charge them for upstream services they use. Has the charge achieved this goal?

A. Yes. QGC Exhibit 3.30 shows that the imbalance volumes (lines 8 and 10) have been declining substantially over time as a result of the charge. Since the implementation of the charge, the majority of customers have materially improved their daily nominations. Very few customers have large daily imbalances, and those who do are paying higher charges based on the services they use. The data suggests the charge is functioning as intended, and is achieving the stated goals.

VI. TARIFF CHANGES

Q. Are you sponsoring an exhibit for proposed changes to the Company's Utah Natural Gas Tariff PSCU 400 (Tariff)?

A. Yes, attached as QGC Exhibit 3.31 is a summary of the Company's proposed Tariff changes. The table references each section the Company proposes to change and provides an explanation of the reason for the change. Each change falls into one of four general categories: 1) changes required to more clearly reflect current Company practices; 2) movement or deletion of sections; 3) clean-up changes including rewording, referencing, punctuation, formatting and grammatical corrections that do not affect the meaning or applicability of the Tariff; and 4) substantive changes explained in testimony. I will address the proposed substantive changes in Tariff Sections 2.02, Tariff Section 8.03 and Tariff Section 9.03.

Q. In Section 2.02 of the Tariff, the Company proposes to add a manual meter reading fee of $15 per month. What is the purpose of this charge?

A. The Company currently has a very small number of customers who have requested the removal of the transponder on their meter because they believe the low level radio frequency waves being emitted by the transponder could adversely affect their health. With the removal, the Company must manually read the meter going forward. The proposed change allows the Company to be responsive to these customer concerns and at the same time allows the Company to recoup the additional costs related to manually reading the meter.

Q. How many customers have requested removal of the transponder on their meters?

A. In the past three years, about 10 customers have made this request.

Q. Is there evidence to support the belief that low-level radio frequencies cause adverse health effects?

A. No. The Company can find no evidence that low-level radio frequencies cause health problems. Low-level- radio-frequency wave exposure happens every day. Cell phones, microwaves, Wi-Fi devices, Bluetooth, radio signals and cordless phones are just a few sources of low-level radio frequency waves.

Q. How was the $15 per month calculated?

A. In order to read a meter manually, a meter reader must drive to a home and manually check the meter. This calculation is based on the assumption that a meter reader could do 25 manual reads per day, including the time to travel to each home and to manually read the meter. Assuming the labor and overhead costs of the employee would be $40/hour and vehicle costs of $40 per day, the cost would amount to $15 per meter.

Q. Please explain the Company's proposed changes to Tariff Section 8.03.

A. In the Residential subsection under the heading SECURITY DEPOSITS, the Company proposes to require the greater of the highest month's bill or a $125 security deposit for customers with prior fraudulent history, bankruptcies or refusal to provide valid identification.

Q. Why is the Company proposing this change?

A. Currently, the Tariff states that residential customers may pay a security deposit in three equal monthly installments and that it may be based on 1 times the highest monthly charge at the premise. There are situations where the highest bill is $30 dollars, making the monthly installment $10. In such situations the Tariff allows a high-credit-risk customer (one with prior fraudulent activity, bankruptcy or no identification for example) to initiate gas service with a $10 payment. The proposed Tariff change would set the deposit for a high credit risk customer at the higher of 1 times the highest monthly charge or $125.

Q. How was the $125 amount calculated?

A. The calculation is based on the typical bill calculation from the last pass through filing in Docket 16-057-05. In that docket, the Company calculated the typical high January bill to be $124.25. Assessing a deposit that is similar to the highest monthly typical bill will help to reduce credit risk.

Q. Does that conclude your testimony?

A. Yes.

State of Utah)
) ss.
County of Salt Lake)

I, Kelly B Mendenhall, being first duly sworn on oath, state that the answers in the foregoing written testimony are true and correct to the best of my knowledge, information and belief. Except as stated in the testimony, the exhibits attached to the testimony were prepared by me or under my direction and supervision, and they are true and correct to the best of my knowledge, information and belief. Any exhibits not prepared by me or under my direction and supervision are true and correct copies of the documents they purport to be.

____
Kelly B Mendenhall

SUBSCRIBED AND SWORN TO this 1st day of July, 2016.

____
Notary Public