BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF DOMINION ENERGY UTAH TO INCREASE DISTRIBUTION RATES AND CHARGES AND MAKE TARIFF MODIFICATIONS	Docket No. 19-057-02

DIRECT TESTIMONY OF

KELLY B MENDENHALL FOR

DOMINION ENERGY UTAH

July 1, 2019

DEU Exhibit 1.0

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Kelly B Mendenhall. My business address is 333 South State Street, Salt Lake City, Utah.

Q. By whom are you employed and what is your position?

A. I am employed by Dominion Energy Utah ("Dominion Energy", "DEU" or the "Company") as Director of Regulatory and Pricing. I am responsible for state regulatory matters for Dominion Energy in Utah.

Q. What are your qualifications to testify in this proceeding?

A. I have listed my qualifications in DEU Exhibit 1.01.

Q. Attached to your written testimony are DEU Exhibits 1.01 through 1.13. Were these prepared by you or under your direction?

A. Yes, unless otherwise stated. If otherwise indicated, they are true and correct copies of what they purport to be.

Q. What is the purpose of your testimony in this Docket?

A. My testimony summarizes the merger commitments agreed to in Docket 16-057-01, and addresses how the Company has complied with these commitments. I also provide a status report of the Infrastructure Replacement Adjustment Tracker ("Infrastructure Tracker" or "Tracker") program, request that the program be continued, and propose that the annual expenditure level be increased from the current allowed $70.9 million to $80 million. My testimony also discusses the test period that the Company believes best reflects the rate-effective period.

My testimony explains that, in compliance with paragraph 33 of the Settlement Stipulation in Docket No. 16-057-01 (the "Merger Stipulation"), Dominion Energy is filing a general rate case between July 1, 2019 and December 31, 2019. My testimony also describes the commitments agreed to in the Partial Settlement Stipulation and the directives the Utah Public Service Commission ("Commission") ordered in the last general rate case (Docket No. 13-057-05). Additionally, Dominion Energy is seeking rate relief for its capital expenditures, including return, depreciation, property taxes, and expenses related to pipeline integrity compliance.

Also, I introduce the Company's witnesses who support the proposed return on equity of 10.5% and overall cost of capital of 7.73%, the proposed test period, the revenue requirement, the cost-of-service and rate-design proposals, and proposed changes to the Company's Utah Tariff No. 500 ("Tariff").

II. INTRODUCTION OF WITNESSES

Q. Please identify the Company's witnesses?

A. Mr. Robert Hevert, a Partner at ScottMadden Inc., will provide testimony supporting the Company's capital structure, cost of debt, cost of equity, and overall rate of return.

Mr. Jordan K. Stephenson, Manager of Regulation for DEU, provides testimony supporting the proposed test period and showing that the selected future test period best reflects the conditions that will exist during the rate-effective period. Mr. Stephenson also provides the revenue requirement for the proposed test period.

Mr. Austin C. Summers, Manager of Regulation for the Company, provides testimony supporting the Company's cost-of-service model and rate design for all rate classes.

Ms. Jessica L. Ipson, Regulatory Analyst for DEU, provides a summary of the Tariff changes proposed by the Company.

III. BACKGROUND

Q. Can you summarize the relief the Company is requesting?

A. Yes. The Company has identified a $19.2 million revenue deficiency and seeks a rate increase to address that deficiency.

Q. Why is the Company filing a general rate case at this time?

A. The Company's last filed general rate case was in Docket 16-057-03. That case was ultimately withdrawn in accordance with paragraph 33 of the Merger Stipulation, which provides: "Within (5) days of the filing of this executed Settlement Stipulation, Questar Gas will petition to withdraw its pending application before the Commission in Docket No. 16-057-03" and "[t]he Parties further agree that Dominion Questar Gas will not file a general rate case to adjust its base distribution non-gas rates, as shown in Questar Gas' existing Tariff, prior to July 1, 2019 or later than December 31, 2019, unless otherwise ordered by the Commission." The Company files this rate case in compliance with these provisions.

Q. Are there additional drivers that are causing the Company to seek rate relief in this docket?

A. Yes. The projected 2020 rate base is $1.8 billion, about $800 million higher than the 2014 test period rate base in the 2013 general rate case. The return, depreciation and property taxes associated with this rate base are the main drivers for the requested increase.

Q. Are there cost offsets that have helped to reduce the increase the Company is seeking in its rate base?

A. Yes. Projected adjusted system Operating and Maintenance expenses have decreased considerably since base rates were last approved in Docket 13-057-05. In that rate case, the 2014 test period O&M expenses for Utah amounted to $128.5 million. The proposed O&M expenses in this case are $119.7 million, or $8.8 million lower than they were six years ago. These expense reductions are driven mainly by lower pension expense and operating efficiencies. Additionally, the impacts of the Tax Cuts and Jobs Act of 2017 have helped keep income tax expense low, and customer growth has resulted in an increase in collected revenue of approximately $85 million. All of these factors have helped to minimize the size of the requested rate relief.

Q. You mentioned that the 2016 general rate case was withdrawn. Were there commitments or directives agreed to by stipulation and/or ordered by the Commission in the Report and Order issued February 2, 2014 in Docket No. 13-057- (2013 Rate Case Order) that are still outstanding and need to be resolved?

A. There were multiple commitments and directives in the 2013 Rate Case Order, including several addressed in the Partial Settlement Stipulation in that same docket. Most have been resolved in prior proceedings; the remainders are addressed in the direct testimony in this docket. The 2013 Rate Case Order addressed the following seven issues: 1) the study of main and service extension policy (2013 Rate Case Order, Section V, paragraph D.); 2) the evaluation of issues related to self-installation of pipelines (2013 Rate Case Order, Section V, paragraph F); 3) the requirement to include depreciation study updates in customers' rates (Partial Settlement Stipulation, paragraph 29); 4) the study of IS and TS issues such as meter aggregation and FS load factor (Partial Settlement Stipulation, paragraph 28); 5) the commitment to provide revenue neutral percentage changes for each rate schedule based upon the Company's cost-of-service study in the next general rate case (Partial Settlement Stipulation, paragraph 27); 6) the requirement to provide specific reports related to the Infrastructure Tracker (Partial Settlement Stipulation, paragraph 22); and 7) the commitment to explore potential changes to interruption of transportation customers and other issues related to transportation service (Partial Settlement Stipulation Regarding TS Tariff Language, paragraph 8).

Q. Please describe how the Company has complied with each of these directives.

A. The table below provides a summary.

Directive	Result
1) Study main and service extension policy.	Resolved pursuant to the Order Addressing Pilot Program issued on June 11, 2015 in Docket No. 13-057-05.
2) Evaluate issues related to self-installation of pipelines.	Resolved pursuant to the Order Addressing Pilot Program issued on June 11, 2015 in

	Docket No. 13-057-05.
3) Include depreciation study updates in customers' rates.	Resolved pursuant to the Report and Order issued June 6, 2014 in Docket 13-057-19.
4) Study IS and TS issues such as meter aggregation and FS load factor in interim workgroups.	*See* discussion in the testimony of Austin Summers DEU Exhibit 4.0.
5) Provide revenue neutral percentage changes for each rate schedule based upon the Company's cost-of-service study in the next general rate case.	*See* DEU Exhibit 4.6, page 2.
6) Provide specific reports related to the Infrastructure Tracker,	*See* Kelly B Mendenhall testimony, DEU Exhibit 1.0, Section VI.C.
7) Explore potential changes to interruption of transportation customers and other issues related to transportation service.	These matters were resolved in Docket Nos. 14-057-19 (In the Matter of the Formal Complaint Against Questar Gas Company Regarding Nomination Procedures and Practices for Transportation Service Customers), 14-057-31 (In the Matter of the Application of Questar Gas Company to make Tariff Modifications to Charge Transportation Customers for Use of Supplier Non-Gas Services), and 18-057-T04 (Application of Dominion Energy Utah to make Tariff modifications relating to transportation service).

IV. TEST PERIOD

Q. What is the Company's proposed test period in the rate case?

A. The Company is proposing an average 12-month test period ending December 31, 2020. Mr. Stephenson discusses how the proposed test period best reflects the conditions the Company will encounter during the rate-effective period.

Q. What assurances can the Company provide that its forecasted test period is reliable?

A. With respect to both Capital Expenditures and Operation and Maintenance (O&M) expense, Mr. Stephenson's DEU Exhibit 3.09 shows that for the last five years the Company's capital expenditures and O&M expense have been, on average, within 1%

and 1.5%, respectively, of forecasted levels. Overall, the Company's budgeting and planning process has been accurate and reliable.

V. DOMINION RESOURCES, INC. AND QUESTAR CORPORATION MERGER

Q. On September 16, 2016, the Utah Public Service Commission approved the merger of Questar Corp. and Dominion Resources, Inc. (now Dominion Energy, Inc.) ("DEI"). What is the status of the integration activities related to this merger?

A. The integration activities are complete. The Company reorganizations have taken place, and the accounting, IT and other systems are fully integrated.

Q. DEI and Dominion Energy Utah both agreed to a number of specific commitments in the Merger Stipulation. Have DEI and DEU complied with these provisions?

A. Yes. There were 65 paragraphs in the Merger Stipulation, 57 of which were specific commitments. Paragraph 36 of the Merger Stipulation required Dominion Energy to file quarterly merger integration updates. These reports provide the status and details about all of the merger commitments. I have attached all of these reports as DEU Exhibit 1.02.

Q. Has Dominion and the Company complied with these commitments?

A. Yes. With one exception, where the Company received Commission approval to amend the commitment, DEU has fulfilled all of the Merger Stipulation provisions.

Q. Are there any specific provisions that you would like to highlight in your testimony?

A. Yes. I'd like to highlight several of the key provisions that are applicable in this case. I've summarized these provisions in the table below.

Merger Stipulation Provision Number	Provision Summary
8	Maintain capital spending
10	Fair consideration and opportunities for employees impacted by the reorganization

Merger Stipulation Provision Number	Provision Summary
11	Pension funding
23	Common equity percentage of total capitalization
37	Transaction costs
38	Transition costs
39	O&M per customer cap
47	Customer satisfaction standards

A. *Merger Stipulation Provision 8 – Maintain Capital Spending*

Q. What was the specific merger commitment related to capital spending?

A. Paragraph 8 of the Merger Stipulation states: "Questar Gas and Dominion share the common focus on installing, upgrading and maintaining facilities necessary for safe and reliable operations. This focus will not be diminished in any way as a result of the Merger. Absent a material change in circumstances, Dominion Questar Gas will continue its planned total capital expenditure program with an estimated $209 million investment in 2017, $208 million investment in 2018, and $233 million investment in 2019 (excludes investment in peak shaving facility). Any variances to this plan will be supported by Dominion Questar Gas in its next general rate case. Dominion will maintain the environmental monitoring and maintenance programs of Dominion Questar Gas at or above current levels."

Q. Please explain how the Company's capital spending is in compliance with paragraph 8.

A. The table below shows the comparisons between the committed spend amounts and the actual amounts.

	Budget (Millions)	Actual (Millions)	Variance
2017	$209	$211	$2

	Budget (Millions)	Actual (Millions)	Variance
2018	$208	$212	$4
2019	$233	$233	$0
Total	$650	$656	$6

As the table shows, the Company complied with this commitment and actually spent slightly more than the committed amounts.

B. *Merger Stipulation Provision 10 – Employee Consideration*

Q. What considerations were given to employees that might be impacted by the reorganization?

A. Provision 10 of the Merger Stipulation states: "Dominion will give employees of Dominion Questar and its subsidiaries due and fair consideration for other employment and promotion opportunities within the larger Dominion organization, both inside and outside of Utah, to the extent any such employment positions are re-aligned, reduced, or eliminated in the future as a result of the Merger."

Q. How has Dominion complied with this commitment?

A. The Company reorganization impacted the areas of affiliated companies that provide support to DEU. Areas such as finance, accounting, human resources, information technology and treasury were reorganized over a long period of time to allow for the handoff of institutional knowledge, allow for a more seamless integration, and to give employees time to find opportunities either inside or outside of the Dominion Energy family of companies.

Q. Please explain the time period and steps taken during the reorganization.

A. DEU implemented an involuntary severance plan (ISP) in August 2017. Fifty-six employees were included in the ISP. The Company took steps to mitigate the impact that the merger had on these displaced employees. First, the Company delayed the termination dates for most of the employees, staggering these dates from September 2017 through December 2018. This allowed about one third of the affected employees to find employment in other areas of the Company, or with the Company's affiliates. Next, a severance package was provided to employees who were separated from the Company. This package included a two-month advance start date and three weeks of severance for each year of service up to 52 weeks.

Q. How many employees were ultimately impacted by the involuntary severance plan?

A. When the involuntary severance plan was complete, 37 employees of the ISP affected employees (of over 900 total employees) were impacted. The other 19 ISP affected employees were able to find other opportunities in the Company.

C. *Merger Stipulation Provision 11 - Pension Funding*

Q. What was the commitment related to pension funding?

A. Paragraph 11 of the Merger Stipulation states that **"**Dominion, as at shareholders' cost, will contribute, within six months of the Effective Time, a total of $75,000,000 toward the full funding, on a financial accounting basis, of Questar Corporation's (i) ERISA-qualified defined-benefit pension plan in accordance with ERISA minimum funding requirements for ongoing plans, (ii) nonqualified defined-benefit pension plans, and (iii) postretirement medical and life insurance (other post-employment benefit ("OPEB")) plans, subject to any maximum contribution levels or other restrictions under applicable law, thereby reducing pension expenses over time in customer rates. Dominion represents that said $75,000,000 contribution, based on current plan funding, would be permissible and well within maximum contribution levels and other restrictions under applicable law.**"**

Q. Did this funding occur?

A. Yes. The contribution was funded on January 19, 2017. This funding has resulted in lower O&M expenses for the foreseeable future. For comparison, the projected pension expense used in the 2020 test period in this case is $0 while the pension expense in 2015, the year before the merger was +$5.5 million. The pension funding was a large driver in the reduction in pension expense.

D. *Merger Stipulation Provision 23 - Common Equity percentage*

Q. Did the Company agree to maintain its common equity percentage within a certain range?

A. Yes. Paragraph 23 of the Merger Stipulation states that "Dominion, through Dominion Questar, will provide equity funding, as needed, to Dominion Questar Gas in order to maintain an end-of-year common equity percentage of total capitalization in the range of 48-55 percent (48-55%) through December 31, 2019.

Q. Please explain what occurred with this commitment?

A. Factors that were not related to the merger required that this provision be amended after approval by the Commission. The reduction in the income tax rate created by the Tax Cuts and Jobs Act put pressure on the cash flow and credit metrics of DEU, which could have resulted in a downgrade to DEU's credit ratings and higher debt costs for customers. In order to maintain the favorable credit metrics of the Company, it was necessary to seek Commission approval to issue equity to buy back debt that would push the equity capitalization levels above the 55% limit of this merger provision. As such, to make this change while honoring the original intent of the Merger Stipulation and holding customers harmless, the Company, the Division, the Office, the Utah Association of Energy Users, and the American Natural Gas Council, agreed that, in its next general rate case, the requested equity percentage would not exceed 55%. This agreement was approved by the Commission on January 4, 2019 in Docket 18-057-23.

Q. How was the provision amended?

A. The provision was amended to read, (changes italicized), "Dominion through Questar Gas will provide equity funding, as needed, for the first four calendar years following the Effective Time, in order for Questar Gas to maintain an end-of-year common equity percentage of total capitalization in the range of 48 to 55 percent through December 31, 2019. *If, during the first four calendar years following the Effective Time, Questar Gas increases its common equity percentage of total capitalization above 55% to maintain credit metrics, the equity percentage of total capitalization proposed by Questar Gas in its first general rate case after the Effective Time shall not exceed 55%. In the second general rate case following the Effective Time, Questar Gas will work to maintain and propose equity levels that are within the equity level ranges of a basket of A rated peers. If it proposes an equity level above the equity level ranges of a basket of A rated peers it must specifically identify factors unique to Questar Gas that prevent being within that range. The Parties do not intend that allowing equity capitalization at or above 55% creates any presumption that the outcome of a general rate case would allow equity capitalization at or above 55%."*

Q. Has the Company complied with this amendment in the calculation of its revenue requirement?

A. Yes. Although the Company's projected equity capitalization for 2020 is 60%, the Company is only requesting a 55% equity capitalization level.

E. *Merger Stipulation Provision 37 - Transaction Costs*

Q. What commitments did the Company make with respect to transaction costs?

A. Paragraph 37 of the Merger Stipulation states: "Transaction costs associated with the Merger will not be recovered through rates of Dominion Questar Gas or recovered through charges from affiliated companies of Dominion Questar to Dominion Questar Gas. Transaction costs shall be defined as: i) Legal, consulting, investment banker, and other professional advisor costs to initiate, prepare, consummate, and implement the Merger, including obtaining regulatory approvals, ii) Rebranding costs, including website, advertising, vehicles, signage, printing, stationary, etc. ii) Executive change in control costs (severance payments and accelerated vesting of share-based compensation), iv) Financing costs related to the Merger, including bridge and permanent financing costs, executive retention payments, costs associated with shareholder meetings, and proxy statement related to Merger approval."

Q. Has the Company complied with this commitment?

A. Yes. DEU and Questar Corporation incurred $17 million and $57.2 million respectively in transaction costs from 2016 through 2018. All of these costs have been booked below the line and have been excluded from the proposed revenue requirement**.**

F. *Merger Stipulation Provision 38 – Transition Costs*

Q. What was Dominion's commitment related to transition costs?

A. Paragraph 38 of the Merger Stipulation states: "Any transition or integration expenses arising from the Merger will not be deferred for future recovery from customers and will be expensed by Dominion Questar Gas and its affiliates as incurred during the transition period. Dominion Questar Gas' revenue requirement for the purpose of developing distribution non-gas rates will be evaluated in the next general rate proceeding, and that filing shall identify all transitions costs, if any, in the base period and the test period. Transition or integration costs that are capitalized and not expensed, including, but not limited to, information technology investments in new hardware and software, including related costs, to convert, conform, and/or integrate Questar Corporation and subsidiaries' systems into and with Dominion's systems, will be itemized and disclosed in the next general rate case. Dominion Questar Gas will have the burden of proof to show that the transition or integration costs are reasonable and result in a positive net benefit to customers."

Q. Paragraph 38 states that "no transition costs will be deferred to future periods." Has DEU complied with this requirement?

A. Yes. No transition costs have been deferred into future periods.

Q. Paragraph 38 states further that the Company shall "identify any transition costs included in the base period and the test period in this filing and that the Company shall have the burden of proof to show that any transition costs provide a net positive benefit to customers." Please identify the transition costs included in the case and the rationale for why these costs should be included in the revenue requirement.

A. There are no transition costs included in the base period or forecasted test period in this rate case. The $26.5 million in transition costs for Questar Gas/DEU and $62.6 million for Questar Corporation were booked below the line.

Q. Paragraph 38 also states that any transition costs that are capitalized and not expensed should be identified in the general rate case. Were any of the transition costs capitalized?

A. No. All of the transition costs related to the merger were expensed.

G. *Merger Stipulation Provision 39 - O&M Per Customer*

Q. What commitments were made about operating and maintenance expenses?

A. Paragraph 39 of the Merger Stipulation states: "Dominion Questar Gas will not seek recovery in its next general rate case of any increase in the aggregate total Operating, Maintenance, Administrative and General Expenses (excluding energy efficiency and bad debt costs) per customer over the 12 months ended December 2015 baseline level, unless it can demonstrate that the increase in such total expenses was not caused by the Merger. This amount per customer for the 12 months ended December 2015 was $138.24. For the first four calendar years following the Effective Time, Dominion Questar Gas will provide, on an annual basis, a baseline comparison between 2015 and the current year for Operating, Maintenance, Administrative and General Expenses for Questar Pipeline and

Wexpro. Additional detail and the calculation of the 2015 baseline for Questar Gas, Questar Pipeline and Wexpro are shown in Attachment 1."

Q. How has the O&M per customer of the Company compared to the 2015 baseline of $138.24?

A. The table below provides the O&M per customer number since 2015.

Year	O&M per customer
2016	$129.88
2017	$111.37
2018 (Base Period)	$113.72

It should be noted that in 2017 due to the transition in accounting systems, no corporate overhead was allocated to DEU and as a result this number was lower than it would have been with corporate allocations. As the table shows, the O&M per customer amounts are considerably lower than the 2015 baseline amount of $138. This reduction of expenses results in a large benefit that will be passed to customers in this general rate case.

H. *Merger Stipulation Provision 47 - Customer Satisfaction Standards*

Q. What commitments were made related to customer satisfaction standards?

A. Merger Stipulation provision 47 states: "Within 120 days of the Effective Time, Dominion Questar Gas will meet with the Division and the OCS on a collaborative basis and update Customer Satisfaction Standards, taking into account recent historical results. Dominion Questar Gas will report quarterly on its performance relative to the Customer Satisfaction Standards. Quarterly reporting will continue until Dominion Questar Gas' next general rate case filing. If the Dominion Questar Gas service levels become deficient, meaning they fall short of the Customer Satisfaction Standards as shown in the report, Dominion Questar Gas will file a remediation plan with the Commission explaining how it will improve and restore service to meet the Customer Satisfaction Standards."

Q. How have those metrics compared to the actual goals?

A. The Company has been presenting the results on a quarterly basis since the 3rd quarter of 2017. The most recent report was calculated for the 1st quarter of 2019, and I have attached this report as DEU Exhibit 1.03. The 11 quarters of reported data represent 660 observations. Of those 660 observations, the Company has met or exceeded the goal 626 times, or 95% of the time. There were 34 instances where the Company did not meet the goal.

Q. Were these deficiencies isolated to specific metrics?

A. Yes. There were six metrics that were impacted. I've summarized these deficient metrics in the table below.

Metric	**Goal**	**Number of deficiencies (11 quarters of data)**
Percentage of calls answered within 60 seconds after customer chooses menu option	85%	4
Average wait for customer after menu selection	Less than 45 seconds	7
Amount of time talking with customer and completing request	5 minutes	4
Read each meter monthly	99%	11
Percentage of billing inquiries responded to within 7 business days	95%	1
Response time to investigate meter problems and notify customer within 15 business days	95%	7

Of the six metrics that were impacted, three seemed to be sporadic misses where there was no real trend and where the deficiencies were not material. For example, the amount of time talking with a customer and completing a request was set with a goal of 5 minutes and there were quarters when the average time was 5.1 minutes. The three metrics that had a trend of being deficient were average wait time for customer after menu selection, read each meter monthly, and response time to investigate meter problems and notify customer within 15 business days. I discuss each of these metrics in more detail.

Q. Please discuss the metric to read each customer meter monthly.

A. This was the most concerning metric for the Company over the last couple of years. The goal for this metric is to read meters monthly 99% of the time and the Company has not been able to meet this goal during the ongoing transponder replacement period.

Q. Was the deficiency in this metric caused by the merger?

A. No. The meter reading metric has been impacted by faulty transponder batteries. The Company is currently replacing the faulty Elster meters with Itron meters and this replacement is expected to be complete in 2020. This replacement will resolve this issue. The Company discussed the transponder battery issue and the plan to resolve the problem in a technical conference on January 9, 2018. I have attached the presentation as DEU Exhibit 1.04.

Q. Please discuss the "average wait time" and "percentage of calls answered within 60 seconds" call metrics.

A. The goals for these metrics are that a customer will wait on average less than 45 seconds per call after menu selection and that 85% of calls are answered within 60 seconds after the customer chooses the menu option. These are ambitious metrics but the Company was able to meet it four out of the 11 quarters where the metric was measured for the average wait time, and seven out of the 11 quarters for the percentage of calls answered within 60 seconds.

Q. Was the deficiency in this metric caused by the merger?

A. No. With respect to the customer care metrics, the issues were mainly caused by high turnover. This turnover was caused by people taking other opportunities both inside and outside the Company. During 2018, the customer care center was challenged with lower staffing levels. This contributed to longer wait times particularly during 2018. The staffing levels have improved in 2019, and the result for the 1st quarter of 2019 was 30 seconds for average speed of answer and 92% of calls answered within 60 seconds, both meeting goal targets. The ability of the customer care group to meet these metrics will be tied to their ability to manage staffing levels and advance more self-serve options.

Q. Please discuss the metric for response time to investigate meter problems and notify customers within 15 business days.

A. This metric is also driven by the battery transponder issue. When meters are not read due to transponder error they are estimated based on historical usage. If a customer's usage has fluctuated significantly from year to year, this could cause a large difference between the estimated usage that is billed and the actual usage. This difference results in customer calls, and this higher call volume takes up additional resources to answer these requests. The goal for this metric is that 95% of the time the Company will respond within 15 days. For the last year, this metric has averaged 88%. It is expected that when the transponder replacement is complete the meter problem call volume will decrease and the Company should meet this goal.

Q. What is your overall conclusion after reviewing the merger commitments and the results over the last three years?

A. Dominion Energy Utah has complied with the commitments it made at the time of the merger. Many of these commitments have resulted in cost savings that customers will enjoy after the completion of this rate case.

VI. INFRASTRUCTURE TRACKER

Q. Would you please describe the Company's Infrastructure Rate Adjustment Mechanism ("Infrastructure Tracker")?

A. Yes. The Commission approved the Infrastructure Tracker as a pilot program in Docket Nos. 09-057-16 and 13-057-05, subject to review in the Company's next general rate case. The description and requirements of the Infrastructure Tracker are provided in Section 2.07 of Dominion Energy Utah's Natural Gas Tariff No. 500 ("Tariff"). Replacement Infrastructure, as approved in the above mentioned dockets, is defined as new high-pressure and intermediate high-pressure infrastructure that is replacing aging high-pressure and intermediate high-pressure infrastructure as required to ensure public safety and provide reliable service. The Company is allowed to track costs that are directly associated with Replacement Infrastructure through an incremental surcharge assigned to each rate class.

Q. Does the Company have reporting requirements associated with the Infrastructure Tracker?

A. Yes. The Company is required to file its next-year's annual plan and budget describing the estimated costs and schedule for the Replacement Infrastructure with the Commission no later than November 15 of each year. The Company is also required to file quarterly progress reports describing the Infrastructure Tracker program. Annual Replacement Infrastructure investment is limited to $65 million, adjusted annually for inflation. The surcharge is assigned to each rate class based on the Commission-approved total pro rata share of the DNG Tariff revenue ordered in the most recent general rate case. The Company is required to track costs associated with the Replacement Infrastructure separately, by sub-account, from other accounts. At the time of the next general rate case, all prudently incurred investment and costs associated with the surcharge are included in base rates and the proposed infrastructure surcharge is reset to $0.00.

A. Infrastructure Tracker Pilot Program

Q. The Infrastructure Tracker was approved in Docket Nos. 09-057-16 and 13-057-05 as a pilot program. Over that time, has the Infrastructure Tracker successfully functioned as intended?

A. Yes. The Infrastructure Tracker has facilitated the successful and expedited replacement of aging pipe, ensuring the continued safety and reliability of Dominion Energy's distribution system. The Infrastructure Tracker reporting framework has also allowed for increased transparency in reviewing and understanding investment decisions made by the Company. It eliminates the risk of forecasting errors because rate adjustments occur only when projects are complete.

Q. Are there any additional benefits that are provided by the Infrastructure Tracker mechanism?

A. Yes. The Infrastructure Tracker reduces the pressure for more frequent, costly general rate cases driven by significant capital expenditures. The Company and the regulators anticipated these benefits when the Infrastructure Tracker was originally proposed and approved. The Infrastructure Tracker is also viewed favorably by the credit rating agencies, and is one of the reasons why the Company has been able to maintain its positive credit rating.

Q. Have the credit rating agencies discussed this favorable view in their credit opinions?

A. Yes. The most recent credit opinion for DEU was issued January 30, 2019. This report is attached as DEU Exhibit 1.05. On page 3 of that document Moody's states: "The Company's infrastructure rider accelerates the recovery of certain distribution system investments, once the projects are complete. This will be particularly helpful as the company makes capital expenditures associated with a multi-year high-pressure natural gas feeder-line replacement program. We expect this replacement program to continue to keep Questar Gas' capital expenditures elevated for several years, therefore the rider will accelerate the recovery of this investment and help to maintain a stronger financial profile than would otherwise be possible."

Q. Why are favorable credit ratings important for customers?

A. A company's credit rating is one of the factors that debt investors use to determine the risk of their potential investments. A company with a strong credit rating is perceived to be lower risk and as a result enjoys lower debt costs than a company with a higher perceived risk. These debt costs are included in the general rate case as a component of customer rates. So these favorable credit ratings lead to lower customer rates.

Q. Has the Company followed the scope and intent defined in the two dockets mentioned above?

A. Yes. In Docket No. 09-057-16, the Company defined the type of infrastructure that would be scheduled for replacement under the Infrastructure Tracker. In testimony and presentations to the Utah Division of Public Utilities (Division), the Office of Consumer Services (Office), and the Commission, the Company provided a list of pipelines that would be replaced. The Company also explained that "[t]his is not one, neat, tidy project that can be identified and completed within the framework described in § 54-7-13.4. Replacing this type of aging infrastructure will take many years and will occur incrementally throughout that period."[1] In that docket, the Company explained it was still in the process of identifying the specific pipe segments that would be scheduled for replacement, and that the situation was dynamic.[2] Parties agreed to Tariff language that allowed for schedule and prioritization changes.[3] Pursuant to Commission order, the Company reports on those pipelines that will be replaced in the upcoming year and how much is spent on these replacements in comparison to the annual budget. During the three years following this initial implementation (2011-2013), the Company completed the replacement of thousands of feet of high pressure feeder lines and complied with the

[1] Docket No. 09-057-16, QGC Exhibit 1.0, Direct Testimony of Barrie L. McKay page 13.
[2] February 10, 2010 Technical Conference, Docket No. 09-057-16.
[3] Tariff Section 2.07.

reporting and spending requirements established in Docket 09-057-16.[4] The Division's audit of the program in 2014 found that "the Company has fulfilled the reporting requirements as stated in the Tariff" and "the program is beneficial to both ratepayers and shareholders."[5] In 2016, the Division's audit stated: "Based on the information provided by the Company, the tracker has worked by allowing the Company to recover capital expenditures without filing a general rate case."[6]

Q. Was there a change to the Infrastructure Tracker in Docket No. 13-057-05?

A. Yes. Following the initial three-year period, the Infrastructure Tracker was expanded to include 70 miles of specified intermediate high pressure ("IHP") belt mains, and the annual spending cap was increased to $65M adjusted for inflation. In addition, the Company agreed to further enhance the reporting of pipeline replacement and scheduling as it developed its "Master Lists" of high pressure ("HP") and IHP pipelines and criteria used in developing replacement schedules. The Company is working with regulators to make enhancements to its reporting and the transparency of this program.

Q. Based on these updates and schedules described above, has the Company met its projections shown in its annual budget each year?

A. Yes. Although the projections provided in November of each year require forward-looking assumptions concerning complex situations, the Company is pleased to have been within 0.4% of cumulative budgeted annual spending since 2013.

	Budget	**Actual**	**Variance**
2013	$59,000,000	$54,890,577	(4,109,423)
2014	65,000,000	68,233,344	3,233,344
2015	62,866,656	66,425,036	3,558,380
2016	70,890,000	70,556,816	(333,184)

[4] 2011-2013 spending cap ($55M plus inflation) was $183M compared to actual spending of $172.4MM.
[5] Infrastructure Tracker Pilot Program Report dated June 17, 2013, Division of Public Utilities, Dockets 09-057-16 and 13-057-05.
[6] Audit of Questar Infrastructure Tracker Pilot Program dated June 28, 2016, Division of Public Utilities, Dockets 09-057-16 and 13-057-05.

2017	69,417,000	68,991,700	(425,300)
2018	63,870,000	63,379,559	(490,441)
Total	**$391,043,656**	**$392,477,032**	**$1,433,376**
% Variance			**0.37%**

Q. In the past three years, has the number of natural gas utilities with infrastructure replacement programs continued to increase?

A. Yes. As more natural gas utilities have recognized the need to address and replace aging and/or non-compliant infrastructure to ensure safety and reliability, mechanisms to allow for recovery of costs between rate cases have become more common in the industry. Today over 74 natural gas utilities in 109 different jurisdictions in 43 states have implemented programs to address the replacement of different varieties of infrastructure.[7]

Q. Is the Company proposing that the Infrastructure Tracker be continued?

A. Yes. The current estimated replacement schedule for HP and IHP pipe demonstrates that replacement will continue at least through 2036. The Company believes that the Infrastructure Tracker, which has been tested, refined, and improved over the past nine years, continues to be the best option for addressing this type of substantial ongoing investment.

B. Spending Level and Variance

Q. Is the Company proposing any changes to the spending level calculation that is allowed annually in the Infrastructure Tracker?

A. Yes, the current spending cap of $65 million adjusted for inflation results in $72.2 million in 2020, as shown in DEU Exhibit 1.06, column F, line 7. The Company proposes that this amount be increased to $80 million as the new base in 2020, with future years being adjusted for inflation using the currently approved CPI index.

[7] American Gas Association Report, "State Infrastructure Replacement Activity" dated May 6, 2019.

Q. Why is the Company proposing to increase the cap to this level?

A. The construction costs of these replacement projects are outpacing the inflation rate that is calculated using the Global Insight GDP inflator. Additionally, construction best practices have changed over the past nine years which has also added to the costs of these projects.

Q. You mentioned that construction costs are increasing at a faster rate than the GDP inflator. What specific costs are increasing?

A. One major component of these pipeline replacements for the Company is the steel cost. DEU Exhibit 1.07 shows a quarterly comparison of the CPI inflation rate and various steel price indexes between the second quarter of 2016 and the first quarter of 2019. As the exhibit shows, steel prices have been increasing at a considerably faster rate than the consumer price index. This is just one of many inputs that do not necessarily track with the GDP inflator.

Q. Has the Company seen higher costs in the pipe that it has purchased?

A. Yes. DEU Confidential Exhibit 1.08 shows the price that the Company has paid for the last four years for various sizes and grades of pipe. As the exhibit shows, the price for 8" grade 52 pipe has increased by about 9% from 2014 to 2018, and the price for 12" pipe has increased by 27% over the same time period. In contrast, over the same period, the infrastructure budget has increased by 6%.

Q. You mentioned that construction best practices have changed over the past nine years. Specifically, which construction practices have caused project costs to increase?

A. Practices such as horizontal drilling improvements, methane reduction, pickling practices and AC mitigation have increased the initial cost of pipeline installation. These practices were discussed in greater detail in the Infrastructure Tracker annual update meeting on April 10, 2019 in Docket Nos. 17-057-25 and 18-057-22. A redacted copy of this presentation is attached as DEU Redacted Exhibit 1.09. Slides 29 through 35 discuss the new construction practices.

Q. Please provide a brief summary of horizontal boring practices.

A. Horizontal boring practices are discussed on pages 30 and 31 of the DEU Redacted Exhibit 1.09. When boring under sensitive areas (water ways, wetlands, railroads, environmental contaminants, freeways and interstates), the Company conducts additional work such as geotechnical studies and risk assessments to ensure that the bore does not create a rupture which disturbs the sensitive area with drilling mud.

Q. Are there benefits and potential cost savings that come from this practice?

A. Yes. These practices avoid the risk of spills like those shown in DEU Redacted Exhibit 1.09, preventing environmental damage and costly cleanups and fines that could result from an inadvertent return into a sensitive area.

Q. Please provide a brief description of the methane reduction practices that the Company is currently utilizing?

A. The greatest methane release associated with construction of HP pipelines is evacuating gas from existing pipelines to tie/weld new pipeline into the system. DEU's practice that greatly reduces methane release involves isolating (via valves or fittings) the section of pipeline that will accommodate the tie-in; once isolated we utilize customer demand to pull the pressures down over time from high pressure (125-1333 psi) to IHP (45 psi). The Company also purchased ZeVac pumps that are used to pump gas from isolated sections of pipe during tie-ins. This reduces the amount of methane released into the atmosphere which has environmental benefits as well as helps to reduce lost and unaccounted for gas on the system.

Q. Please explain "Pickling".

A. Pickling is a method of treating a new pipeline to ensure that new pipes do not absorb the odorant that has been injected into gas, thereby preserving the odorized gas for delivery downstream. The Company odorizes natural gas supplies as required by federal regulations as a safety measure to ensure that customers can smell a gas leak. In its natural state, natural gas is odorless. Odorant serves as an important signal when there is a gas leak. New pipelines can absorb odorant from gas supplies, essentially removing it from the gas and creating an unsafe situation for the public and end-use customers. Pickling is a process that involves injecting odorant into the pipeline at intervals to ensure that, as absorption occurs into the pipeline, the gas remains odorized. This practice increases the safety of the system for customers and the public and keeps DEU compliant with federal regulations.

Q. Please discuss AC mitigation and how it benefits the integrity of the system.

A. As growth occurs in the major population areas of Utah, electric lines come with it. These lines often create currents in the ground that can cause corrosion to gas pipelines. AC mitigation involves the installation of zinc ribbon and zinc matting on pipelines and facilities to create a ground that eliminates the current and the threat of corrosion. While this adds to the cost of the pipe during installation, that cost is more than justified by the long-term benefits provided, including the extension of the useful life of the pipe and the added safety for employees and the public.

Q. Are there any cost savings that come from the replacement of aging infrastructure with new pipe that has been installed using current construction practices?

A. Yes. Typically, because new lines have been constructed using modern practices approved by the Pipeline Hazardous Materials Agency ("PHMSA"), they fall under the distribution integrity management program instead of the transmission integrity management program. This means that they are not subject to some of the regulations governing pipes in high consequence areas like the requirement for inline inspection and other assessment method regulatory requirements. This ultimately reduces the pipeline integrity expenses. The Company still uses these methods, but does so less frequently. This helps, and will continue to help, reduce the integrity management costs for this pipe in the future. Additionally, as shown in the depreciation study addressed by Mr.

Stephenson in his pre-filed direct testimony, the replacement of these main lines has increased the depreciable life of the mains from 65 years to 70 years. This reduces the depreciation expense related to the mains account by over $2 million per year.[8] As more of this aging pipe is replaced, one would expect that the useful life of these main lines would continue to be extended.

Q. Have the increased costs related to the program caused a delay in the completion of the overall program?

A. Yes. A comparison of the feeder line replacement list filed with the Commission in April 2016 and the one filed in April 2019 show that the feeder line replacement program completion date has been postponed from 2030 to 2036. This is caused mainly by the cost increases I have discussed.

Q. Are there any other factors that have changed since 2009 that the Commission should consider as it reviews the Company's request to increase the Infrastructure Tracker?

A. Yes. When the Infrastructure Tracker was originally approved in 2010, it amounted to a larger portion of the Company's total capital spend than it does today. A summary of the Company's total capital spend compared to the Infrastructure Tracker spend is shown in DEU Exhibit 1.10, Tracker vs. Capital Spend. As the exhibit shows, in 2011, the first full year of the Company's Infrastructure Tracker program, the Company spent $58.8 million on the Infrastructure Tracker program and about $68.8 million on non-tracker spend. In 2019, the Infrastructure Tracker budget is $70.9M compared to a non-tracker budgeted amount of $162.3 million. While some of this investment provides incremental revenue through new customer growth, a lot of the investment is non-revenue generating maintenance capital, and the Company and its shareholders must wait for the next general rate case to receive cost recovery for it. This regulatory lag makes it difficult for the Company to recover its cost of service.

[8] This reduction in expense was calculated by taking the projected 2020 average investment in Account 376 mains of $1,948,166,146 divided by the difference between 70 year and 65 year depreciable lives.

Q. In recent years, the Company has had some budget variance over the calculated spending cap. Is the Company proposing a method to treat such spending variances going forward?

A. Yes. Over the years, the Company has experienced spending variances that are typical and expected with these types of construction projects. Some years have been under budget while some have been over. In addition, there have been projects that have been added to the scope of replacement work during a given budget year that had not originally been included in that year's budget. This occurred in 2016 with Feeder Lines 51 and 89. The Partial Settlement Stipulation in Docket No. 13-057-05 did not address how budget variances would be treated.

Q. How does the Company propose to address such variances?

A. To the extent there are spending variances in the annual budget, the Company proposes to adjust for the variance in the infrastructure replacement surcharge calculation. DEU Exhibit 1.11 is the calculation of the revenue requirement used in every Infrastructure Tracker filing. The exhibit shows the proposed adjustments for hypothetical budget variances for years 2020 and 2021. In years when spending exceeds the allowed cap there would be a reduction to the Infrastructure Tracker investment used in the rate base calculation the next time the Company seeks to adjust the surcharge. In this example, the Company spends $2 million over the cap in 2017. Row 3 shows the $2 million reduction to rate base resulting from that overage.

By contrast, in years when the Company's annual spending in the Infrastructure Tracker program is below the allowed spending cap, to the extent that the accumulated underspent amount is less than the accumulated overspent amount, the amount underspent would be netted against overspent amounts. Row 4 shows a $1 million adjustment for an assumed underspent amount in 2018. If there is no overspent amount, there would be no adjustment to rate base when actual spending is lower than the cap. If the Company is in an overall net-overspent position, the net overspent amount would not be recovered in rates until the next general rate case.

Q. Would the Company continue to track and report all of the spending for these projects separately as it currently does?

A. Yes. The Company would continue to track and report all of the investment including those dollars that are over the spending limit. The only change would be the adjustment to the revenue requirement calculation discussed above.

Q. In recent years, variances have been addressed by reducing the budget of the following year. Why is the Company proposing different treatment?

A. There are some negative planning and operational impacts to reducing the planned budget in a given year. By nature, these projects involve coordination with many constituents including governmental entities, cities, counties, contractors, customers, employees and other stakeholders. It can be detrimental to efficiencies and relations with these constituents to adjust the schedule after the plan is in place and construction is underway. The Company believes that, because of the complex and consequential nature of these projects, customers and other constituents are best served by allowing the construction schedule and budget to go forward as planned while managing budget variances as an adjustment in regulatory filings. The objective is to replace the identified infrastructure in a timely, effective manner while stabilizing the rate impact on customers. This proposed approach will add flexibility to the planning process.

C. Reporting

Q. Have the reporting requirements for the infrastructure tracker changed over time?

A. Yes. Since 2013, the Company has worked with the Division to hone the parameters, focus the efforts and develop reports that define the scope and the progress made in the infrastructure replacement program. The Company appreciates this collaborative effort as it has provided transparency and clarity to the program.

Q. Please describe the annual Tracker budget and quarterly progress reports the Company filed since its last general rate case.

A. Since the 2013 general rate case (Docket No. 13-057-05), the Company has filed an annual budget in November of each year. Each quarter, the Company has also filed progress reports. Additionally, in April of each year since the 2013 rate case, Company representatives (regulatory personnel, project managers and engineering personnel) have met with representatives from the Commission, the Division, and the Office in publicly-noticed meetings to explain the replacement budget projects, actual costs, variances and plans for the coming year.

Q. Does the Company plan to continue these types of meetings and reporting if the Infrastructure Tracker is approved going forward?

A. Yes. These meetings and reports help keep interested parties informed of upcoming projects and provides a forum to explain progress, changes and variances that are common with these types of projects. These meetings also allow interested parties to ask questions concerning any Infrastructure Tracker issues.

Q. Please describe the other reports provided each year.

A. Pursuant to the Report and Order approving the Partial Settlement Stipulation in Docket No. 13-057-05, the Company has annually provided updated copies of its HP and IHP Master Lists and Replacement Schedules. The Master Lists provide a snapshot of pipe in service by size, vintage year, and feeder line in the case of HP, or county in the case of IHP.

Q. Do these reports inform parties of progress on the Infrastructure Tracker?

A. Yes. These reports provide the annual progress of replacing scheduled pipe, as well as context for the amount of identified pipe remaining on the schedule in upcoming years. An evaluation of the change in the footages shown on the Replacement Schedules for feeder lines and belt mains scheduled for replacement reveals that the Company has replaced approximately 93 miles of HP pipe and 12 miles of IHP pipe. This compares to approximately 330 miles of HP and 58 miles of IHP pipe remaining to be replaced in future years.

Q. Are these reports subject to revisions?

A. As the Company continually learns more about the pipe in its system by evaluating records, conducting tests, and addressing needs throughout the distribution system, the Master Lists are subject to revision. The lists represent a snapshot of the system using the most accurate and up-to-date information the Company has at the time. However, there are times when the Company learns additional information that requires the Master Lists to be updated.

In addition, each project is unique, and as such the current replacement schedule is reviewed on an ongoing basis and is subject to change depending on factors such as pipeline-integrity testing, customer-growth patterns, highly populated areas, capacity constraints and development projects including proposed street-widening projects. Although the replacement schedule may vary for any or all of these reasons, annual expenditures should remain approximately the same.

The Company notes that there are other types of infrastructure such as Aldyl-A pipe, IHP steel pipe and other portions of the IHP system not included on these schedules that may, at some point in the future, also require accelerated replacement. The Company continually evaluates all infrastructure, both inside or outside of the Tracker, to ensure safety and reliability of service.

Q. When did the Company last update its HP Master List?

A. The Company provided the Commission with its HP Master List in May of 2019, in Docket No. 18-057-21.

Q. Please explain the changes that occurred in the scheduled HP footages since the last general rate case.

A. DEU Confidential Exhibit 1.12 is a summary of these changes. Column A lists each feeder line included in the Infrastructure Tracker program. Column D is a summary of the original estimated replacement footage for each feeder line in the Infrastructure

Tracker program. Column E is a summary of all the footage replaced/retired from 2013 to 2015. Column H shows the footage that remained in the 2016 Replacement Schedule. Column I shows the amount of footage replaced and retired since 2016. Column L shows the footage remaining to be replaced as provided in the 2019 Replacement Schedule. In addition to replacement footages (Columns E and I), the remaining footage was also adjusted in response to mapping improvements (Columns F and J), as well as data corrections to two feeder lines (Column G).

Q. Please explain the data corrections in Feeder Line 38 and Feeder Line 97 shown in column G.

A. A review of the Company's mapping database revealed that the 15,913 feet (Feeder Line 47) were not included on Feeder Line 38 in the 2013 Master List because the data was not properly queried. As a result, the footage was inadvertently omitted. This was corrected prior to the 2015 HP Master List update. The 5,600 feet (line 66) in Feeder Line 97, which is the Feeder Line from the old Utah Gas system, were incorrectly entered into the database with an installation date of 2001 (the date Questar Gas purchased the Utah Gas system) rather than 1963 (the installation date). The Company identified this error and corrected the date to reflect 1963. Because these were footage corrections rather than additional feeder lines, the Company believes that they should be included in the Infrastructure Tracker program footage.

Q. Have there been any changes to the Intermediate High Pressure Master List since the last general rate case?

A. The only changes have been those that reflect pipeline retirement due to the replacement of belt lines. DEU Exhibit 1.13 provides a summary of the retirement footages.

Q. Is the Company proposing any changes to the reporting requirements for these master lists?

A. Yes. In prior years, due to challenges getting the mapping data on time, it has been difficult to meet the April 30th filing deadline for these reports. The Company proposes that these deadlines be moved to June 30th. This will allow the Company to have extra time to gather the footage data. This change should not adversely impact the ability of the regulators to review the reports.

Q. What changes has the Company made to the evaluation criteria for the High Pressure and Intermediate High Pressure replacement schedules since the last general rate case?

A. The Company refined its evaluation criteria in 2017, and these changes were discussed in the annual infrastructure replacement technical conference held on April 27, 2017 in Docket Nos. 15-057-19 and 16-057-16. The presentation is attached as DEU Redacted Exhibit 1.14, pages 28-33.

Q. Can you summarize the changes that were made?

A. The risk evaluation is based upon the equation, Risk = Likelihood of Failure (Threat) X Consequence of Failure (Consequence). There were changes made to both the Likelihood of Failure (Threat) calculation and the Consequence of Failure (Consequence) components of that equation.

Q. What changes were made to the threat component of the Risk calculation?

A. There are many factors included in the threat calculation including construction year, pipe/equipment condition, manufacturing process used, pressure test records and whether the pipe is reconditioned or not. The weightings of these factors were updated based on incident counts from the PHMSA database. Now factors such as leak survey data and weld types carry more weight than they did in the past. The level of granularity for each category was also increased. For example, in the prior risk assessment, pipe was categorized as Pre-1955, 1955 to 1970 or post 1970 pipe. In the new risk assessment, the pipe is categorized into one of five different age groups. The manufacturing and pressure test categorizations are also more detailed in nature.

Q. What changes were made to the consequence component of the risk score?

A. Previously, the Company weighted high consequence areas 67% and census data 33% of this component. Now, the weighting is based on population (80%)

Q. Will future pipeline regulations require the Company to expand its pipeline replacement program?

A. Possibly. On August 25, 2011, PHMSA issued an advanced notice of proposed rulemaking for rules related to the Safety of Gas Transmission and Gathering Lines. Because this proposed rule represents the most comprehensive pipeline safety requirements proposed since 1970, it has become known as the "Mega Rule." If the Mega Rule is adopted, it would impose additional requirements for monitoring gas quality, mitigating internal corrosion, and managing external corrosion. The Company expects that the Mega Rule will become final, in some form, later this year. When it does, the Company expects that the rule's requirements could result in new and additional costs for most local distribution companies, including Dominion Energy Utah. It may also expedite the need to replace pipelines that, to date, are not included in either the HP Master List or the IHP Master List.

Q. Does the Company recommend making any other changes to the Infrastructure Tracker program?

A. No. The Infrastructure Tracker program has been functioning well, and as designed, for nearly a decade. The Company believes that all other aspects of the Infrastructure Tracker should continue as they have in the past.

D. Tracker Surcharge to Be Rolled into General Rates

Q. Is the Company proposing to include the infrastructure replacement costs that are included in the current surcharge, in base rates?

A. Yes.

Q. How will this work?

A. All of the plant, accumulated depreciation, accumulated deferred taxes, depreciation expense and taxes other than income taxes that were separately identified in the Infrastructure Tracker filings and that have been separately tracked since the last general rate case have been included in their respective FERC accounts and included in the test period. These costs are part of the total revenue requirement that the Company is requesting in this case and they have been included in the DNG portion of each rate schedule.

Q. What will happen to the surcharge at the time new base rates are approved?

A. The surcharge will be reset to zero. In Ms. Ipson's DEU Exhibit 5.02, Tariff Rate Schedules in 2.02, 2.03, 2.04, 4.02, 5.02, 5.03 and 5.04 illustrate this reset. As can be seen, the Infrastructure Rate Adjustment line shows zero for all block usage**.**

Q. Assuming new rates are set based on an average 2020 test period, at what point in time will replacement investment for feeder lines and IHP beltlines begin to be included in the Infrastructure Tracker?

A. Based on an average 2020 test period, any investment above $82.6 million that is put into service on or after January 1, 2019, should be included in the Infrastructure Tracker. The Company notes that it is proposing an average 2020 test period with a starting point that assumes $50,089,630 million of closed investment in HP Feeder Line and IHP beltline replacement in 2019 and $32,466,650 included in rate base for 2020. The inclusion of incremental investment of Replacement Infrastructure should not begin until the $82.6 million of investment has been reached. Additionally, the effective date of an incremental surcharge related to the Infrastructure Tracker should be set on or after March 1, 2020. Both of these limiting criteria will ensure that no costs have been included twice and that rates are just and reasonable. The Company's first request, following this general rate case, to adjust rates for the cost of Replacement Infrastructure will include evidence showing that these two limiting criteria have been followed. Attached as DEU Exhibit 1.15 is a summary of the Replacement Infrastructure costs that the Company has included in its 2019 and 2020 projected Infrastructure Tracker additions and is the basis for the amount included in the 2020 average test period. (*See* column C, line 28). This calculation uses the same reasoning that was used in the 13-057-05 case.

VII. CONCLUSION

Q. Would you please summarize your recommendations?

A. Yes. The rates proposed by Dominion Energy Utah in this case are just and reasonable. They reflect the prudent costs the Company will incur in providing safe, reliable and adequate service to its customers during the rate-effective period. The cost of service and rate design proposed by DEU represents a fair apportionment of costs among our customer rate classes and provides customers with the correct signals to use natural gas efficiently. I recommend that the Commission approve the proposed revenue requirement, rates and Tariff changes described in the Company's Application and testimony.

Additionally, the Company recommends the Infrastructure Tracker cap be raised to $80 million in 2020 and that it be continued going forward.

Q. Does this 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 July 1, 2019.

Notary Public

GINGER JOHNSON
Notary Public State of Utah
My Commission Expires on:
August 4, 2019
Comm. Number: 684539