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. 22-057-03

REDACTED DIRECT TESTIMONY OF

KELLY B MENDENHALL FOR

DOMINION ENERGY UTAH

May 2, 2022

DEU Redacted 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 and Wyoming.

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 1.07. 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. Can you provide a brief summary of the Company's performance since its last general rate case in 2019?

A. The Company has continued to provide safe, reliable service to customers since its last rate case in 2019 in the midst of a worldwide pandemic. Since 2019, the Company has added about 56,000 customers (for a total of 1.1 million customers total as of year-end 2021) and expects to add an additional 48,000 customers by the end of the 2023 test period. The Company has also invested over $755.4 million from 2019-2021 and plans to spend about $1.5 billion in capital from 2022 to 2026. These capital expenditures are necessary to sustain new growth and continue to ensure safety and reliability on the system.

Q. What is the purpose of your testimony?

A. I will introduce the Company's witnesses who support the proposed return on equity and overall cost of capital, the proposed capital structure, 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"). My testimony will also provide a status update on the

Magna liquified natural gas ("LNG") facility, the costs of which are included in the test period. I will also provide testimony supporting the continuation of the Company's Infrastructure Rate Adjustment tracker mechanism and discuss the treatment of the rural expansion capital investment in the rate case.

II. INTRODUCTION OF WITNESSES

Q. Please identify the Company's witnesses.

A. Jennifer Nelson, a Partner and Assistant Vice President from Concentric Energy Advisors, provides testimony supporting the Company's capital structure, cost of debt, cost of equity, and overall rate of return.

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.

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

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

III. BACKGROUND

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

A. Yes. The Company has identified a $70.5 million revenue requirement deficiency and seeks a rate increase to address that deficiency.

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

A. The Company is required to file a rate case every three years while the Infrastructure

Tracker is in effect.[1] This filing meets that requirement. Additionally, the Company projects that revenue collected through currently approved rates during the test period will not be sufficient to recover expected expenses and a fair return on capital and, as a result, the Company seeks approval from the Commission to avoid this shortfall.

IV. TEST PERIOD

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

A. The Company is proposing an average 13-month test period ending December 31, 2023. Mr. Stephenson discusses how the proposed test period best reflects the conditions the Company will encounter during the rate-effective period.

Q. Is the proposed test period consistent with the statute that governs this proceeding?

A. Yes. Utah Code Ann. § 54-4-4 provides that, "the [C]ommission 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." The statute further provides that, "the [C]omission shall select a test period that, on the basis of evidence, the [C]ommission 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 average 2023 test period meets these criteria.

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[1] (Commission Order, Docket 09-057-16 (June 3, 2010), attached as Appendix A, paragraph 19)

Q. What is the basis for the Company's position 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 3.17 shows that for the last five years the O&M regulatory forecasts have been, on average, within 1% of targeted levels. As DEU Exhibit 3.24 shows, the capital budget forecasts have also been within 1% of forecasted levels. This demonstrates that the Company's budgeting and planning process has consistently been accurate and reliable. Mr. Stephenson provides additional support and detail for the forecasts in his testimony.

V. CAPITAL STRUCTURE

Q. What rate of return and capital structure is the Company proposing in this case?

A. The Company's proposed overall rate of return is 7.35%, 0.17% higher than the current Commission-approved return of 7.18%. As discussed further by Jennifer Nelson, a higher return is necessary due to risk factors such as higher capital requirements, increased market volatility, changes in Federal Reserve monetary policy and the impacts of inflation. A summary of the capital structure components is shown in the table below:

	Weight	Cost	Weighted Cost
Long Term Debt	46.79%	4.00%	1.87%
Common Equity	53.21%	10.3%	5.48%
Total	100%		7.35%

VI. EXPENSES

Q. How have expected increases in expenses impacted the requested revenue requirement in this case?

A. Since the general rate case in 2019, O&M expenses have increased by about $18.1 million. As Mr. Stephenson further explains, approximately $3 million of the increase is caused by inflationary pressures the Company faces across its operations, net of known savings, with the remainder related to the Company's new LNG facility, increasing labor and labor overhead costs, and proposed updates to the annual pipeline integrity management programs. As I discuss further below, the Company has invested a significant amount of capital over the past three years to address system reliability and customer needs, leading to increases in depreciation and property tax expenses.

Variances are provided in the table below:

	2019 Rate Case	2023 Proposal	Variance
Operating Expenses	$118.4 million	$136.5 million	$18.1 million
Depreciation	$85.1 million	$107.8 million	$22.7 million
Taxes	$59.1 million	$80.3 million	$21.2 million
Total	$262.6 million	$324.6 million	$62.0 million

VII. COVID IMPACTS

Q. Please summarize what operational changes the Company made to assist customers in response to the pandemic.

A. As the Commission is aware, in early 2020, in Docket 20-057-T03, the Company filed for a variety of tariff waivers to minimize any service impacts to customers and to protect our employees. The table below provides a timeline of these waivers and when waived actions were reinstated.

Waiver	Date Waived	Date Reinstated
Allow DEU to reconnect all customers who have been disconnected for nonpayment	3/16/2020	7/18/2020
Waive reconnection fees going forward	3/16/2020	7/18/2020
Waive all late fees to its customers	3/16/2020	4/7/2021
Suspension of in-home Home Energy Plan Assessments	3/16/2020	7/1/2021

Q. In addition to the tariff waivers, were there any other changes the Company made to help ease the financial burden of the pandemic on customers?

A. During the pandemic, in addition to the tariff waivers, the Company took additional measures to aid homeowners and small business customers. Customers who had been shut off for non-payment were offered reconnection of service without the requirement of a deposit. For customers experiencing financial hardships, we offered additional payment arrangements that were designed to accommodate individual customer needs, not only allowing them more time to pay but also lowering initial payment amounts to ensure continued gas service. Also, after the resumption of late payment fee charges on past-due balances, we continued to offer zero-interest on payment arrangement plans to ensure that we reduced the financial hardship experienced by our customers.

Q. What efforts did the Company take to help customers understand the financial assistance options available to them?

A. Our customer assistance team worked diligently to promote and educate customers on both REACH and HEAT throughout the pandemic. The REACH program made changes in both the eligibility and approval process to provide our credit-challenged customers more government assistance to pay their utility bills during the pandemic. Essentially, REACH aligned with our existing HEAT program in Utah opening the door for customers of all ages to receive assistance from both programs with a streamlined approval process that qualified customers for both programs. In addition, the benefit amount increased $100, from $250 to $350, while maintaining the additional $50 benefit for veterans and active military personnel.

Q. How did the tariff waivers impact the Company financially?

A. The Company anticipated that these tariff waivers would result in higher bad debt and lower late fee revenue. However, because the pandemic began just as the 2019/2020 winter heating season was ending, because the Company made policy changes to help customers with financial difficulties, and because there were funds available to help customers pay their bills, the impacts on bad debt expense were not as large as they could have been. In fact, as shown in DEU Exhibit 3.12, the bad debt has decreased from 0.25% in 2019 to 0.17% in 2020 and 2021. Fortunately, Dominion Energy customers were able to manage their bills through additional flexibility of payment options and the assistance programs that were available.

The Company did see a decrease in late fee revenue. The reduction in late fee revenue can be quantified by comparing 2019, a non-COVID year, with 2020 and 2021. A comparison of the late fee revenue for these three years is shown in the table below:

Year	Late Fee Payments (FERC Account 487)
2019	1,885,271.11
2020	635,130.70
2021	1,166,053.39

As the table shows, the pandemic negatively impacted the Company's ability to collect late fees. Using 2019 as a proxy for what 2020 and 2021 would have been absent COVID, the Company collected $1,969,358 less revenue than it would have all things being equal.

Q. Did the Company try to collect this lost revenue from customers through a deferred accounting order or some other mechanism?

A. No. The lost late payment revenue caused by the tariff waivers was borne by shareholders.

Q. Has pandemic-related inflation and supply chain issues impacted the Company's capital costs?

A. Yes. The Company has seen increases in almost all construction costs over the last three years. To provide an example, the Company manages construction costs through 18 construction zones, 16 in Utah and two in Wyoming. Every three years, the Company grants the construction rights in each zone to an individual contractor based on a zone bid process. In most instances, the zone construction is awarded to the lowest bidder. The most recent zone bids were awarded for the 2021-2023 construction period. On average, the construction costs for all the activities in the 16 Utah zones have increased about 29% over the zone bid pricing for the 2018-2020 time period. A summary of the increases by cost component is attached in DEU Confidential Exhibit 1.02. DEU also saw pandemic related cost increases on its LNG facility, which I discuss in further detail later in my testimony.

Q. What impact do these overall cost increases have on the Company?

A. The Company has capital requirements each year to manage system growth and maintenance. Inflation and supply chain constraints could create cost pressures resulting in the Company not being able to perform as much work as it did in past years. If these cost pressures continue, it will require the Company to increase its annual capital spending from current levels in the coming years to manage growth and maintenance on its system.

VIII. RATE BASE

Q. Please summarize the changes to rate base since the last case.

A. As Mr. Stephenson testified, "ongoing capital investment is the lifeblood that sustains a safe, reliable, and growing natural gas distribution system. Each year, the Company must invest a significant amount of capital to address customer growth, replace aging infrastructure, and expand the distribution system to meet system requirements and needs."

The Company's rate base has grown considerably since the last rate case in 2019. The projected 2023 rate base is $2.56 billion, about $770 million higher than the $1.79 billion 2020 test period rate base approved in the 2019 general rate case. The return, depreciation, and property taxes are all impacted by this increase in rate base. This needed capital investment includes a combination of projects to address growth and maintenance issues on the Company's system, as well as the construction of the LNG facility in Magna, Utah.

Q. The LNG facility is the largest capital expenditure during the last three years. Has this facility been reviewed by the Commission in prior proceedings?

A. Yes. In Docket 19-057-13, the Company sought pre-approval of a Voluntary Resource Decision to construct the on-system LNG Facility In that proceeding, the Company shared the results of a request for proposal ("RFP") it issued for proposals to address supply reliability concerns. The Company's analysis showed that, based on the results of that RFP, the lowest cost option to address those reliability concerns would be for the Company to construct and operate an on-system LNG facility. Additionally, based upon other qualitative factors, including, among other things, control of the facility, reliability of the proposals, and location, the Company provided evidence that a Company-owned LNG facility was the best option to ensure supply reliability.

Q. Did the Commission grant preapproval to construct the facility?

A. Yes. On October 25, 2019, the Commission issued an Order in Docket No. 19-057-13: (1) approving DEU's voluntary request for pre-construction approval of its resource decision to construct the LNG facility, and the project costs of $210,157,307; (2) designating the

LNG facility as a materially strategic resource under the provisions of the Merger Agreement approved in Docket No. 16-057-01; and (3) stating that any increase to the approved cost had to be presented to and approved by the Commission for the Company to recover costs above the previously-approved amount.

Q. Is the Company expected to exceed the $210.2 million that was originally approved in Docket 19-057-13?

A. Yes. As I discuss in detail below, due to COVID-related cost increases and supply chain issues, the current project is expected to cost $218.6 million, an overage variance of just over 3.5% from the original approved amount. This update was presented on February 17, 2022 to the Commission and other parties in the Company's IRP technical conference in Docket 22-057-02.

Q. What does § 54-17-404 of the Utah Code say about the approval of an increase to projected costs?

A. A utility can take one of two approaches. First, a utility "may seek a commission review and determination of whether the energy utility should proceed with the implementation of an approved resource decision." Utah Code. Ann. § 54-17-404 (1)(a). If an energy utility seeks Commission review under this provision, the Commission may then grant approval for the utility to proceed and incur the additional costs, in which case the utility will be entitled to recover the additional costs, or the Commission could determine that the utility should not proceed with the implementation of the resource decision. This determination must be made within 60 days.

Q. What is the second alternative?

A. An energy utility can proceed with the project and seek recovery of the excess costs in a cost-recovery docket such as a general rate case. If the Commission approves the cost overage, the energy utility is entitled to recover those costs in rates.

Q. What Approach did the Company elect to take?

A. The Company only became aware that it would exceed the originally approved cost of the project and was able to quantify that overage in late 2021 after the LNG facility was substantially completed. By that time, it was neither practical nor appropriate to pause construction to seek additional Commission review. To do so would have resulted in greater cost increases, as well as a delay of the anticipated in-service date for the nearly-completed facility. Furthermore, as I discuss later, even with the increased costs, the LNG facility is still the lowest cost option. Accordingly, the Company decided to address the overage and the recovery of the associated costs in this proceeding. Because the LNG facility will be in-service during the pendency of this docket, all parties and the Commission will have the necessary time to review the final, actual project costs without having to do so on an expedited basis. The additional costs have been included in Mr. Stephenson's revenue requirement calculation.

Q. You mentioned that the LNG project is expected to exceed the original commission preapproval amount. What is the Company's current cost estimate for the project?

A. A summary of the variance is provided in the table below:

	Preapproval	New	Variance
Facility Capital Cost	$211,157,307	$ 218,563,414	$7.4 million
Additional Thermal Exclusion Area	$0	[redacted]	[redacted]

Q. Please explain the components of the increased facility capital costs.

A. In the preapproval docket, the Commission approved a capital expenditure of $210,157,307. Additionally, in the revenue requirement model, the Company included $1,000,000 per year of ongoing maintenance capital. The updated total capital project cost is expected to be $218,563,414. For purposes of the cost recovery in this case, the Company has included $217,563,414 through 2022 with an additional $1,000,000 of capital in 2023 for a total project cost of $218,563,414.

Q. What caused the project cost increase?

A. The COVID-19 pandemic affected the global supply chain and commodity prices worldwide. It closed mining operations and manufacturing facilities, creating shortages in raw materials and basic products. It also created labor shortages. All the while, many essential projects continued to move forward and consume the supplies that were in stock. This situation created unprecedented material shortages which caused unforeseen escalation in the cost of the materials and unanticipated delays in getting the equipment and materials needed for the LNG facility and caused shortages in workers needed to complete the project. As a result, Matrix, the contractor on the project, identified several categories where the costs exceeded the original bid cost, due in substantial part to the extraordinary and unforeseeable circumstances created by COVID. Matrix submitted a force majeure claim under the terms of its contract for cost and schedule relief. Ultimately, Matrix's claim and the parties' contractual rights and obligations were resolved through a settlement agreement. Pursuant to that agreement, [redacted]. A summary of the specific items that gave rise to the increases is summarized in the table below:

COVID Related Change order items			
Cost Description	Contractor Proposal	Estimate of COVID Related Costs	Settled Amount
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		[redacted]

Q. You mentioned earlier that the project cost is $7.4 million higher than originally anticipated. How does this amount reconcile with the $[redacted] million summarized in the table above?

A. While COVID related costs caused an [redacted] million increase to the project, [redacted] of those costs have been absorbed into the original project cost. For this reason the Company is requesting an increase of $7.4 million to the project.

Q. [redacted]

A. [redacted]

Q. [redacted]

A. [redacted]

[redacted]

Q. [redacted]

A. [redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

Q. [redacted]

A. [redacted]

[redacted]

Q. [redacted]

A. [redacted]

Q. [redacted]

A. [redacted]

[redacted]

Q. Please provide the background on the [redacted] thermal exclusion zone you identified earlier in testimony.

A. As part of the LNG facility construction, 49 CFR Part 193 & NFPA 59A code compliance requires thermal radiation exclusion zone analysis to identify any potential impact areas extending beyond the property line of the LNG facility, should there be an incident at the facility. A map of the LNG facility and the thermal radiation zone is attached as DEU Exhibit 1.04. The yellow square on the map shows the original land purchased for the project. The red circle on the map identifies the thermal radiation exclusion zone. The initial assessment by the Company's subject matter expert, HDR, concluded that the off-site exclusion zones would not be impacted because they had not been developed for occupancy "at the time of siting". In the fourth quarter of 2020, it was determined after detailed design review discussions with PHMSA that the Company in fact would be required to control development and occupancy within the exclusion zones, including those falling outside the purchased property, for the life of the plant.

Q. What impact did this have on the project?

A. The thermal radiation zone impacted two adjacent properties: a 15.4-acre parcel owned by Kennecott Utah Copper LLC ("Kennecott") (shown in purple), and a 3.9-acre parcel by Magna Water District ("Magna Water") (shown in green). The area of the exclusion zone extending into these properties is shown in light purple and light green on DEU Exhibit

1.04. To control development and occupancy within the exclusion zone of those properties, the Company was required to purchase restrictive covenants from Kennecott and Magna Water for [redacted] and [redacted], respectively. Through these restrictive covenants, the Company can now control use of and development in the off-site thermal radiation exclusion zones for the life of the plant. The restrictive covenants prohibit gatherings and construction in the identified areas and grant the Company the control necessary to satisfy the federal regulations as interpreted by PHMSA.

Q. What is the accounting treatment for these restrictive covenants?

A. [redacted]

Q. You mentioned earlier that the on-system LNG facility was chosen not only due to qualitative factors but it was also the lowest cost option. Do the $7.4 million additional project costs and the [redacted] thermal exclusion zone costs change the ranking of the original options?

A. No. As mentioned above, even taking into account the cost increases and including them into the original analysis, the on-system LNG facility is still the lowest cost option. The original calculation was included in DEU Highly Confidential Exhibit 1.07 offered in Docket 19-057-13. I have shown the options central to that docket in DEU Highly Confidential Exhibit 1.05, compared to the current LNG facility costs, including COVID-related cost impacts. It is worth noting that my comparison does not adjust any of the costs for other project options considered in that prior docket for COVID-related price pressures, even though those projects would have been subject to the same kinds of price increases that have been experienced by the LNG facility. In other words, the revenue requirements for projects #2 and #3 were left unchanged. In this respect, my comparison is very conservative. I have updated that analysis in DEU Highly Confidential DEU 1.05. As the exhibit shows, the On-system LNG facility is still the lowest cost option.

IX. INFRASTRUCTURE RATE ADJUSTMENT MECHANISM

Q. Is the Company proposing any changes to the Infrastructure Rate Adjustment Mechanism (Infrastructure Tracker Program or ITP)?

A. The Company is not proposing any substantive changes to the program. The Company is only requesting that the program be allowed to continue as it has previously been approved by the Commission.

Q. Does the Company believe that the continuation of this program continues to be in the public interest?

A. Yes. In its Report and Order issued on February 25, 2020 in Docket 19-057-02 ("Commission Order") the Commission stated: "We find and conclude that continuing the ITP is in the public interest because it facilitates the needed replacement of aging infrastructure in a manner that encourages a relatively constant amount of investment in between rate cases and allows for a transparent process regarding the work accomplished and the work remaining to be done." (Commission Order, at page 10). Further the Commission determined: "We conclude a spending cap indexed for inflation (by the same GDP deflator index included in the most recent stipulation) balances customer and shareholder interests. Accordingly, we find that a spending cap of $72.2 million is just and reasonable in result and we approve a spending cap at that level. We conclude that indexing that spending cap for inflation (by the same GDP deflator index we approved in the most recent GRC) balances ratepayer interests with the objectives of the ITP. The GDP deflator will continue to be used as an annual index to adjust the cap on an ongoing basis." (Commission Order at page 13). The Company agrees with the statements the Commission made in the last general rate case and believes that they are still relevant today. The Company requests that the Commission approve the continuation of the ITP at the current budget level, adjusted in future years using the GDP deflator.

Q. Is the Company proposing to include the cumulative total infrastructure replacement costs that have been previously included in the current surcharge, into base rates?

A. Yes.

Q. How does it propose to do so?

A. All of the plant, accumulated depreciation, accumulated deferred taxes, depreciation expense and taxes other than income taxes that were separately identified in the ITP proceedings and that have been separately tracked since the last general rate case have been included in their respective FERC accounts and included in the average 2023 test period. As such, these costs are part of the total revenue requirement proposed by Mr. Stephenson, and they have also been included in the DNG portion of each rate schedule proposed by Mr. Summers.

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

A. The surcharge will be reset to zero. DEU Exhibit 5.02 includes Tariff Rate Schedules in 2.02, 2.03, 2.04, 4.02, 5.02, 5.03 and 5.04, which illustrate this reset. As can be seen, the Infrastructure Rate Adjustment line shows zero for all block usage. In effect, all ITP costs and associated surcharge will be "rolled up" into the base DNG rate upon the effective date of the Commission order in this docket.

Q. Assuming new rates are set based on an average 2023 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. The Company has included $84.7 million of ITP capital spend in rate base in the proposed average 2023 test period. Attached as DEU Exhibit 1.06 is a summary of the ITP costs that the Company has included in its 2022 and 2023 projected capital additions and is the basis for the amount included in the 2023 average test period. (See column B, line 22). This calculation uses the same reasoning that was used in the rate cases in Docket Nos. 13-057-05 and 19-057-02. This $84.7 million includes a total of $48.8 million added to rate base in 2022 (line 3) and an additional $35.9 million added to rate base in 2023 ($35.9 million is calculated by subtracting the $48.8 on line 9 from the $84.7 on line 22). As such, any investment above $84.7 million that is put into service on or after January 1, 2022 should be included in the future ITP surcharge calculations. Any incremental investment below $84.7 million has been included in the base DNG rate calculation and should not be included in the ITP. Comparing the $84.7 million threshold to the actual ITP capital spend beginning January 1, 2022 will ensure that no ITP costs will 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 ITP infrastructure will include evidence showing that the spending threshold has been exceeded.

Q. Why should the Company begin tracking infrastructure replacement beginning January 1, 2022 and not January 1, 2023, the beginning of the test period?

A. Because the Company has estimated the amount of ITP spending that it will make in 2022, starting the "clock" on January 1, 2022, and using a threshold that includes both 2022 and 2023 estimated ITP spend will ensure equitable rate recovery for both customers and the Company.

Q. Please summarize the Company's request related to the ITP.

A. The Company requests that the ITP be allowed to continue at currently approved spending amounts, adjusted annually using the GDP inflator. Additionally, the Company requests that the threshold of $84.7 million be set and that all actual ITP spending from January 1, 2022 be tracked until the cumulative spending amount has exceeded that threshold, at which point any excess investment be included in the ITP surcharge.

X. RURAL EXPANSION TRACKER

Q. Has the Company included any capital investment for rural expansions in the test period?

A. Yes. The Commission previously approved rural expansion projects to Elberta and Goshen in Docket 21-057-06 and to Green River in Docket 21-057-12. The anticipated completion date for the Elberta and Goshen is late 2022 and the expected completion of Green River is late 2023, and the Company plans to make expenditures in both years for both projects. As a result, the costs of these projects have been included in the test period.

Q. How much has been included in the test period for these projects?

A. DEU Exhibit 1.07 summarizes the amounts included in the test period. As the exhibit shows, there is $12.2 million of spend included in 2022 (line 3) and $24.8 million of spend included in 2023 (line 8). The $24.8 million spend is averaged so that $11.5 million of actual investment for 2023 will be included in base rates ($11.5 million is calculated by subtracting the $12.2 million on line 9 from the $23.7 million on line 22). The total amount for both projects included in base rates is $23.7 million.

Q. The Company has typically collected costs for these rural expansion projects through a rider. How does the Company propose rate recovery for these projects in the future.

A. It is anticipated that the rural expansion cost recovery would be treated like the ITP. Assuming the Commission includes $23.7 million in base rates, that would be the threshold that would need to be spent before the Company would ask to recover rural expansion costs through a rider between rate cases. The tracking of those costs would begin January 31, 2022, and would continue until the threshold would be met.

Q. Can you summarize your proposal related to rural expansion costs?

A. Yes. The Company proposes that the inclusion of $23.7 million of related costs for the Elberta, Goshen and Green River rural expansions be approved in base rates. We also propose that $23.7 million be used as a threshold and that rural expansion costs be tracked beginning January 1, 2022, and that any costs exceeding the threshold be allowed to be recovered through a rider.

XI. COST OF SERVICE/RATE DESIGN

Q. How are the LNG costs being treated in the cost-of-service calculation?

A. The cost of the LNG facility is being allocated to the sales customer classes.

Q. Why are no costs being allocated to the transportation customers?

A. As was discussed at length during prior proceedings regarding the LNG facility, that facility is being built and will be used for the sole benefit of sales customers. As a result, none of these costs will be allocated to transportation customers. As transportation customers are responsible for their own supply reliability, they will not have access to this facility during a supply disruption.

Q. Is the Company proposing to make any major changes to the classes in this case?

A. Yes, the Company is proposing to split the Transportation Service Rate Schedule (Transportation Service Firm and Transportation Service Interruptible) into small, medium and large transportation classes, with distinct rates for each class. This class split is discussed in further detail by Mr. Summers in his direct testimony.

XII. CONCLUSION

Q. Would you please summarize your recommendations?

A. Yes. The rates proposed by Dominion Energy Utah in this case are just and reasonable in result and in the public interest. 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 represent a fair apportionment of costs among its customer rate classes and provide 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.

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 May 2, 2022.

____

Notary Public