**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

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IN THE MATTER OF ADVICE NO. 993-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO INCREASE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL GAS RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE FEBRUARY 24, 2022	**)**	**PROCEEDING NO. 22AL-______G**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF JONI H. ZICH</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

January 24, 2022

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

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TABLE OF CONTENTS

SECTION **PAGE**

I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY 5
II. GAS OPERATIONS CAPITAL INVESTMENT OVERVIEW 10
A. CAPITAL INVESTMENTS IN CORE AREAS 10
B. GAS OPERATIONS BUDGETING PROCESSES.. 15
III. SAFETY OF THE GAS SYSTEM 24
A. SAFETY/PSIA.. 24
B. SAFETY/NON-PSIA.. 26
1. TOOLS AND EQUIPMENT 30
2. CAPITALIZED LOCATING COSTS... 31
3. TRANSMISSION PIPELINE MARKER INSTALL 31
4. ENHANCED LEAK SURVEY – SERVICE RENEWALS 32
5. SAFETY/NON-PSIA - OTHER 34
IV. RELIABILITY OF THE GAS SYSTEM.. 35
A. PUBLIC SERVICE'S CAPACITY PLANNING 35
B. SYSTEM RELIABILITY AND CAPACITY CAPITAL ADDITIONS............................ 39
C. KEY RELIABILITY PROJECTS SINCE THE 2019 HTY THROUGH THE 2022 CTY... 46
1. TUNGSTEN-TO-BLACKHAWK PROJECT 46

TABLE OF CONTENTS

SECTION **PAGE**

2. Granby T-O to YMCA VS 6-inch Project 50
3. Upsize Pipe for Boulder 285# Project 52
4. CO/Winter Park/Winter Park Tie Project 53
5. Failed Meter Lots 58
6. Reliability – Capacity 59
7. Reliability – Other 60
D. Routine Asset Health Investments 63
E. Routine Capacity Investments 66
V. NEW BUSINESS 69
A. Key New Business Discrete Projects Since the 2019 HTY 77
1. Canyons Development 77
2. Aurora Highlands 78
3. New Business – Other 79
B. New Business Routines 80
VI. MANDATED RELOCATIONS 83
A. Discrete Mandated Relocations 84
B. Routine Relocations 88
VII. GAS OPERATIONS TARIFF CHANGES 92
A. Public Service's Gas Transportation Services 92
B. Proposed Gas Operations Tariff Changes 96
1. Primary Receipt Points 98
2. Hourly Receipt and Delivery Quantities 103
3. Gas Quality 105
VIII. CONCLUSION 107

LIST OF ATTACHMENTS

Attachment JHZ-1	Gas Operations Capital Additions October 1, 2019 through December 31, 2024
Attachment JHZ-2	PSIA 2022 Deferral Report Proceeding No. 21A-0071G
Attachment JHZ-3	Capital Additions: Safety/Non-PSIA – Other
Attachment JHZ-4	Reliablity – Capacity Project Descriptions (Projects over $2 million)
Attachment JHZ-5	Capital Additions: Reliability – Capacity
Attachment JHZ-6	Capital Additions: Reliabiliy – Other
Attachment JHZ-7	SCADA – Cost Benefit Analysis Results
Attachment JHZ-8	Public Service New Customer Counts October 1, 2019 through June 30, 2021
Attachment JHZ-9	New Business Project Descriptions (Projects over $2 million)
Attachment JHZ-10	Capital Additions: New Business – Other
Attachment JHZ-11	Capital Additions: Relocations – Other
Attachment JHZ-12	In-Path Receipt Points

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DIRECT TESTIMONY AND ATTACHMENTS OF JONI H. ZICH

I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joni H. Zich. My business address is 825 Rice Street, Saint Paul, Minnesota 55117.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Xcel Energy Services Inc. ("XES") as Senior Director, Strategy, Governance and Planning. XES is a wholly owned subsidiary of Xcel Energy Inc. ("Xcel Energy") and provides an array of support services to Public Service Company of Colorado ("Public Service" or the "Company") and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. I have been employed by Xcel Energy or one of its operating companies for over 30 years. Throughout my career, I have worked in the areas of energy conservation, account management, gas scheduling, trading, and management of upstream interstate transportation and storage services. In 2012, I was promoted to Director, Business Operations and System Strategy Planning. In this role, I was responsible for the strategy and long-term planning of Xcel Energy's gas system. My duties include strategic planning for Xcel Energy's gas operations business unit, managing gas cost recovery mechanisms for integrity management riders, directing all aspects of Public Service's gas transportation services, and leading long-term capacity planning for the Company's high-pressure gas systems. In January 2021, I also began directing the Company's gas governance organization, which includes gas standards, compliance, contractor inspections, quality assurance, and the Pipeline Safety Management System (PSMS), where I was promoted to Senior Director, Strategy, Governance and Planning. A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my Direct Testimony in my Statement of Qualifications.

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes, I am sponsoring the following attachments:

- Attachment JHZ-1 Gas Operations Capital Additions, October 1, 2019 through December 31, 2024
- Attachment JHZ-2 PSIA 2022 Deferral Report

- Attachment JHZ-3 Capital Additions: Safety/Non-PSIA – Other
- Attachment JHZ-4 Reliablity – Capacity Project Descriptions (Projects over $2 million)
- Attachment JHZ-5 Capital Additions: Reliability – Capacity
- Attachment JHZ-6 Capital Additions: Reliabiliy – Other
- Attachment JHZ-7 SCADA – Cost Benefit Analysis Results
- Attachment JHZ-8 Public Service New Customer Counts, October 1, 2019 through June 30, 2021
- Attachment JHZ-9 New Business Project Descriptions (Projects over $2 million)
- Attachment JHZ-10 Capital Additions: New Business – Other
- Attachment JHZ-11 Capital Additions: Relocations – Other
- Attachment JHZ-12 In-Path Receipt Points

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The primary purpose of my Direct Testimony is to present the Company's capital investment in its natural gas business since our last combined gas rate case in Proceeding No. 20AL-0049G ("2020 Combined Gas Rate Case"), which adopted a test year ended September 30, 2019, through the 2022 Current Test Year ("CTY") ("2022 CTY" or "Test Year") being proposed in this case.[1][2] In addition, I provide forecasted capital additions for two "step" years, 2023 and 2024, after the 2022 CTY. The Company's overall capital additions for the 2023-2024 step years are explained in more detail by Company witnesses Mr. Steven P. Berman and

[1] The 2022 CTY encompasses calendar year 2022.

[2] In the 2020 Combined Gas Rate Case, the Administrative Law Judge ("ALJ"), through Decision No. R20-0673 (mailed Sept. 22, 2020), approved an Unopposed and Comprehensive Stipulation and Settlement Agreement ("2020 GRC Settlement"). Decision No. R20-0673 thereafter became a decision of the Commission.

Ms. Deborah A. Blair. I also discuss certain proposed operational-related changes to the Company's gas tariff.[3] My Direct Testimony is organized as outlined below.

- In Section II I provide an overview of the Company's capital investments included in the 2022 CTY and forecasted capital spend for 2023 and 2024. I also describe the Company's budgeting and management processes to support the forecast for capital projects that will be placed in service during the Test Year.
- In Section III I describe the multiple ways Public Service attends to maintaining safety as our first priority. I support the capital investments necessary to maintain system and public safety since the most recent gas rate case, including new safety projects being placed in service between October 1, 2019 and December 31, 2022. I also discuss how the types of investments previously made under the Company's Pipeline System and Integrity Adjustment ("PSIA") rider factor into the case from an operational perspective.
- In Section IV I describe the Company's reliability work. As part of this discussion, I provide information on the Company's capacity planning and the alignment of capacity planning with state policy goals. I also identify capacity projects and key initiatives to improve reliability since the 2020 Combined Gas Rate Case, discussing discrete capacity projects and providing support for routine investments in asset health and capacity.

[3] "Gas Tariff" or "Tariff" refers to the Company's COLO PUC No. 6 Gas Tariff.

- In Sections V and VI I discuss Public Service's investments to serve new customers and to undertake mandated pipeline relocations.
- In Section VII I discuss certain gas operations-related tariff changes being proposed by the Company.

II. GAS OPERATIONS CAPITAL INVESTMENT OVERVIEW

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this Section of my Direct Testimony, I provide an overview of the Company's capital investments included in the 2022 CTY, and include the forecasted capital spend for 2023 and 2024. I also describe the Company's budgeting and management processes to support the forecast for capital projects that will be placed in service during the Test Year.

A. Capital Investments in Core Areas

Q. WHAT ARE THE CORE AREAS OF FOCUS FOR PUBLIC SERVICE'S GAS SYSTEM INVESTMENTS?

A. Safety and reliability are the key areas of focus for Public Service's gas business. In addition, new business resulting from new customers and customer growth, and infrastructure relocations mandated by city, state, or federal authorities, require investments on the gas system. Mr. Luke A. Litteken discusses these four core areas in more detail in his Direct Testimony.

Q. PLEASE SUMMARIZE THE CAPITAL ADDITIONS IN SAFETY, RELIABILITY, NEW BUSINESS, AND RELOCATIONS THAT ARE INCLUDED IN THIS RATE CASE.

A. Table JHZ-D-1 below summarizes the Company's gas operations capital additions since the end of the 2019 HTY utilized as the basis for setting rates in our 2020

Combined Gas Rate Case.[4] The table provides actual capital additions through June 30, 2021, and forecasted capital additions for July 1, 2021 through 2024.

Table JHZ-D-1
Gas Operations Capital Additions
October 1, 2019 – December 31, 2024* ($ millions)

Capital Category	Actual Additions 10/1/2019 - 6/30/2020	2021 HTY Actual Additions 7/1/2020 - 6/30/2021	Forecasted Additions 7/1/2021 - 12/31/2021	2022 CTY Forecasted Additions 1/1/2022 - 12/31/2022	2023 Step 1 Forecasted Additions 1/1/2023 - 12/31/2023	2024 Step 2 Forecasted Additions 1/1/2024 - 12/31/2024
Safety/PSIA	$106.8	$117.3	$142.6	$143.1	$151.8	$179.3
Safety/Non-PSIA	$7.8	$7.4	$9.8	$9.8	$10.2	$6.5
Reliability	$78.6	$153.1	$110.4	$135.0	$158.6	$122.2
New Business	$59.6	$91.4	$51.8	$103.9	$106.0	$112.0
Relocations	$13.4	$24.1	$18.1	$22.3	$22.6	$17.0
Total	**$266.1**	**$393.4**	**$332.7**	**$414.1**	**$449.3**	**$437.0**

* *Differences in sums due to rounding.*

Attachment JHZ-1 to my Direct Testimony provides a detailed list of the capital additions summarized in Table JHZ-D-1 above.

Q. WHAT IS INCLUDED IN THE SAFETY/PSIA CATEGORY FOUND IN TABLE JHZ-D-1?

A. Historically, due to the existence of the PSIA and its separate prudence and reporting requirements, the Company's Safety category in its rate cases focused solely or primarily on non-PSIA projects. However, the PSIA rider was sunset on December 31, 2021, and 2022 PSIA costs are included in a PSIA Deferral in accordance with the Comprehensive Settlement Agreement in Proceeding No. 21A-0071G ("2021 PSIA Settlement").[5] To illustrate the total effect of including

[4] In the 2020 Combined Gas Rate Case, a historical test year ending September 30, 2019 ("2019 HTY") with certain known and measurable adjustments was approved by the Commission and agreed to by the parties as part of a comprehensive settlement.
[5] Approved by the Commission in Decision No. C21-0715.

PSIA capital costs in base rates, we are including the PSIA-related capital investment in Table JHZ-D-1. This approach permits a comparable review of the Company's gas Safety investments for the period provided. Moving PSIA projects to base rates has a substantial impact on base rate capital additions; going forward, a larger portion of our capital additions will be recovered in the ordinary course of business. For example, of the total $449.3 million in capital additions in 2023, $151.8 million (or approximately 34 percent) is related to safety investments that would have otherwise been recovered separately under the PSIA rider but would now be included in base rate recovery. I discuss the Safety/PSIA category in more detail in Section III of my Direct Testimony.

Q. WHY ARE CAPITAL ADDITIONS FOR 2023 AND 2024 INCLUDED IN TABLE JHZ-D-1?

A. While the test year in this case is the 2022 CTY, the Company is requesting step increases for 2023 and 2024 tied to estimated capital investment during those years, as explained by Company witnesses Mr. Berman and Ms. Blair in their Direct Testimonies. While Attachment JHZ-1 reflects the currently forecasted capital investment during those years, this information is provided not to obtain specific approval of the referenced investments at this time, but to illustrate the forecasted level of capital additions at that time. The level of capital investment from an operational perspective is expected to be $449.3 million in 2023 and $437.0 million in 2024.

Q. ARE THE 2023 AND 2024 FORECASTED CAPITAL ADDITIONS REASONABLE?

A. Yes. These forecasts are reflective of actual expected capital investment by gas operations during those years as reflected in the Company's approved five-year plan. The forecasted levels of spend are also generally consistent with our annual gas operations investment today.

Q. WHAT WERE THE PRIMARY DRIVERS OF GAS OPERATIONS' ACTUAL CAPITAL ADDITIONS FROM THE 2019 HTY THROUGH JUNE 2021?

A. The primary drivers of Gas Operations' actual capital additions from the 2019 HTY through June 2021 were Safety/PSIA and Reliability work, with several larger Reliability projects, such as Tungsten to Blackhawk and Granby T-O to YMCA, contributing to the overall capital investment levels. Additionally, customer requests for new business along with mandated infrastructure relocations continue to drive the Company's capital investment.

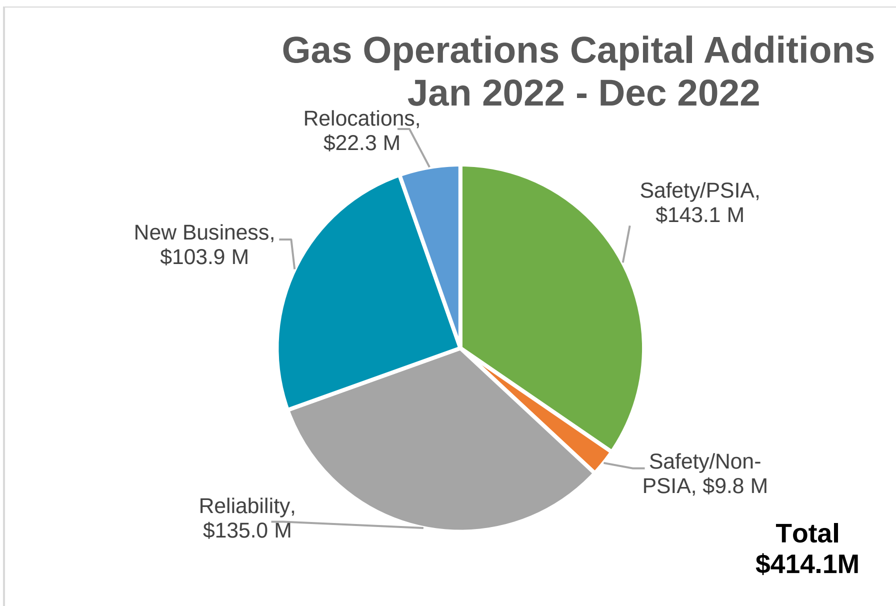
Q. WHAT ARE THE PRIMARY DRIVERS OF GAS OPERATIONS CAPITAL ADDITIONS FOR JULY 2021 THROUGH DECEMBER 31, 2021?

A. The primary drivers of Gas Operations' forecasted capital additions for July 2021 through December 31, 2021 focus on Safety/PSIA work, with the completion of the Southeast Metro Maximum Allowable Operating Pressure ("MAOP") project. In addition, Reliability work is driven by the multi-year Failed Meter Lot exchange program, as well as several large Reliability projects, including the Upsize Pipe for Boulder 285# (EB-20) Project in Broomfield, Colorado, and the Winter Park Tie Project, which I discuss later in my Direct Testimony.

Q. WHAT ARE GAS OPERATIONS' CAPITAL FORECASTS FOR 2022 BY CAPITAL BUDGET GROUPING?

A. In addition to Table JHZ-D-1 above, Figure JHZ-D-1 below illustrates the breakdown of forecasted Gas Operations capital additions for the 2022 CTY by capital budget grouping.

Figure JHZ-D-1
2022 CTY Gas Operations Capital Additions by Category



Q. WHAT ARE THE PRIMARY DRIVERS OF GAS OPERATIONS CAPITAL ADDITIONS FOR THE 2022 CTY?

A. The primary driver of Gas Operations' capital additions during the 2022 CTY are investments related to Safety/PSIA, many of which are captured in the PSIA Deferral as I will discuss further in Section III of my Direct Testimony. As I noted earlier, reliability investments are driven by the multi-year Failed Meter Lot exchange program, with fewer large Reliability projects identified in this time period. Capital additions are also attributable to customer requests for new gas services.

Q. HOW DO GAS OPERATIONS' CAPITAL ADDITIONS FOR THE 2022 CTY COMPARE TO HISTORICAL TRENDS?

A. The anticipated capital additions of $414.1 million for the 2022 CTY are expected to be lower than Public Service's annual capital additions in 2019 of $437.5 million, and 2021 of $470.5 million. Likewise, the 2022 CTY capital additions forecast is lower than the three year average (2019-2021) of $437.5 million. This data is based on plant in service, which can vary based on the timing of project completions. Capital investments can also vary on a year-to-year basis depending on the specific work that is necessary to meet the needs of both our customers and our business. In certain years, Gas Operations' capital investments may be lower due to fewer customer new business requests or municipality requests to relocate our gas infrastructure in public right-of-way. At the same time, Gas Operations' capital investment levels may increase in years when we are working on major initiatives, and capital additions necessarily increase when those initiatives are placed in service.

B. Gas Operations Budgeting Processes

Q. WHAT IS THE PURPOSE OF THIS SEGMENT OF YOUR DIRECT TESTIMONY?

A. In this section, I provide an overview of the Company's budgeting processes and management as additional support for the forecasted capital included in the Company's rate request.

Q. HOW DOES PUBLIC SERVICE BUDGET FOR CAPITAL SPENDING FOR ITS GAS OPERATIONS BUSINESS?

A. There is a well-defined process for identifying, ranking, and budgeting gas capital projects. The key steps necessary to ensure the preparation of a comprehensive five-year capital budget are summarized below.

Step 1: Engineering and operations personnel identify potential risks (issues) and mitigations (solutions).

Step 2: Each risk and mitigation is reviewed for accuracy, completeness, and reasonableness.

Step 3: As each risk and mitigation is considered, it is scored based on certain criteria, such as the likelihood of occurrence, and the consequences of not addressing it.

Step 4: All potential mitigations are ranked or prioritized. Historically the PSIA Rider has had its own risk ranking criteria to determine eligibility for PSIA Rider recovery. As the PSIA Rider and the 2022 PSIA Deferral wind down, former PSIA projects will be prioritized in the ordinary course of business along with all other Gas Operations capital projects.

Step 5: After the ranking is completed, business leadership reviews the list, the level of risk associated with the various projects, as well as overall capital levels based on financial criteria.

Step 6: Projects chosen to be funded are assigned a capital project number based on the type of work. These capital projects are also classified as either “specific” (*i.e.*, “discrete”) or “routine.”

Step 7: Capital projects for large pools of small projects (e.g., main installations, service renewals, etc.) are automatically tied to closing patterns based on the attributes of the work. For larger individual projects, in-service dates are assigned. Project managers then forecast expenditures based on the particulars of a project and its projected in-service date.

Step 8: All capital projects that are included are reviewed and approved, both at the business area level and at the corporate level.

Step 9: Work is deployed during the year, as efficiently and cost-effectively as possible.

The estimated in-service date of each large project and the closing patterns associated with different types of work pools (noted in Step 7 above) determine the date the project goes from Construction Work in Progress ("CWIP") to Plant-In-Service on the Company's books and becomes a plant addition. The process of moving projects from CWIP to Plant-In-Service is described in more detail by Company witness Ms. Laurie J. Wold. Ms. Wold discusses this process as it relates to pulling together the Company's capital budget across all business areas at the corporate level. Since I am representing the Gas Operations business area, the focus of my Direct Testimony is on how the capital projects are developed and ultimately become gas assets.

Q. IN SUMMARIZING THE NINE STEPS ABOVE, YOU REFER TO "RISKS," "SOLUTIONS," "MITIGATIONS," AND "PROJECTS." CAN YOU EXPLAIN WHAT YOU MEAN BY THESE TERMS IN THE CONTEXT OF DEVELOPING A CAPITAL BUDGET?

A. "Risks" are potential detrimental impacts or threats to safety, the quality/reliability of our service, environmental quality, our ability to meet our legal obligations, or our financial standing. These identified risks result in initiatives that address the risks. These initiatives, in turn, often require capital expenditures. In the capital budgeting process, potential "solutions" or "mitigations" are essentially "projects" (i.e., work to be performed that will mitigate a certain risk or set of risks). These projects are the focus of the capital budget process. Projects are evaluated against each other based on their costs, how effectively they address certain risks, and how critical the risks are.

Q. DOES THE COMPANY CONSIDER ALTERNATIVES WHEN EVALUATING GAS INFRASTRUCTURE CAPITAL PROJECTS IDENTIFIED AS PART OF THE FOREGOING PROCESS?

A. Yes. As the Company has discussed in past rate cases, we have included alternative project considerations as part of our gas infrastructure planning processes. In recognition of Xcel Energy's leadership in the clean energy transition, the Company has recently developed a process where non-pipe alternatives to certain capacity and new business projects are also evaluated. Alternatives considered during this process are project specific, but focus on load reduction and shifting techniques (e.g. demand-side management ("DSM"), and customer targeting for firm to interruptible rate conversion) and electrification.

Depending on the circumstances and the project, this process can take as little as one month to as much as nine months or more to complete. Consequently, a limited subset of capacity and new business projects are subject to this additional evaluation. More specifically, capacity projects go through this process based on their risk score and if (a) the project is needed in the next five years; or (b) the project is needed after five years and is greater than $10 million. New business projects go through this process if total project costs are greater than five million dollars and the project is in a capacity constrained area.

As part of this process, we carefully balance our obligation to timely provide safe and reliable gas service, and are respectful of the customer's request for natural gas service, which we are required to provide upon request. However, this process reflects the Company's proactive effort to develop a framework capable of evolving as the transition of the Local Distribution Company ("LDC") under Clean Heat (Senate Bill 21-264), the Company's own Net-Zero Vision, and other recent environmental legislation matures.[6]

Q. PLEASE EXPLAIN THE PROCESS YOU FOLLOW TO GOVERN THE CAPITAL INVESTMENTS AFTER THE CAPITAL BUDGET IS DEVELOPED.

A. Gas Operations along with Corporate Finance, monitors all distribution and transmission capital dollars to ensure that authorized projects align with the established budget. Detailed monthly reports are produced that compare actual capital expenditures and plant in service to budgeted levels for both routine and discrete projects. There are monthly meetings with this group and key stakeholders within the organization to review program and specific project capital expenditures and variances. Adjustments and corrective measures are implemented as needed.

Q. WHAT INCENTIVES ARE IN PLACE TO PROMOTE THE ACCURACY OF THE CAPITAL BUDGET?

A. Management employees that have job responsibilities with a direct impact to capital budget expenditures and plant in service (e.g., Engineering, Investment Delivery) have specific budgetary goals that are incorporated into their

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[6] Company witnesses Ms. Brooke A. Trammell and Mr. Jeff R. Lyng discuss these topics in their Direct Testimonies. Xcel Energy's Net-Zero Vision for Natural Gas report is available at Net-Zero-Vision-for-Natural-Gas.pdf (xcelenergy.com).

performance evaluations. Performance is measured monthly to ensure adherence to these goals and to address variances. This metric is aimed at developing accurate budgets and managing to the budgeted levels.

Q. WHAT IS THE "ROUTINE" PROJECT TYPE YOU MENTIONED EARLIER?

A. Routines are budgets used to fund small projects that are typically less than $300,000 each, and are of a nature and type that are typical or common for a gas utility to perform regularly. The Company has four Routine budgets: Asset Health (Reliability), New Business, Mandatory Relocations, and Capacity (Reliability).

Q. CAN YOU DESCRIBE HOW THE COMPANY BUDGETS FOR ROUTINES?

A. Yes. Because projects that are funded under routines are generally not defined until the current year, the budget is determined based largely on historical actuals. More specifically, routine budgets are based on historical spend and forward-looking customer growth projections for new business provided by Company witness Ms. Jannell E. Marks, while also taking cost escalations into account. Other individual routine projects, such as for new business growth, reinforcements, or rebuilds, are budgeted based on a two-year expenditure history and estimated in-service date. This routine grouping of projects serves to allocate funding for performing core business functions, such as connecting new customers, reconstructing facilities, and purchasing new meters, regulators, and fleet.

Q. WHAT ARE DISCRETE PROJECTS?

A. Discrete projects are typically large (often multi-year) projects, greater than $300,000, in which the Company sets up a discrete work order to track the specific cost of the project. Discrete projects are identified through the Company's Builders

Call Line (New Business), requests from municipal or government agencies (Mandatory Relocations), or through the Company's planning processes (Reliability (Asset Health and Capacity), and Safety).

Q. HOW DOES THE COMPANY BUDGET FOR DISCRETE PROJECTS?

A. During the Company's annual budget cycle, we follow a rigorous budgeting process that identifies the optimal mix of projects and expenditures for a given year. If a discrete project is known and of high enough priority to be included in the annual budget, it is added to the budget during the regular budget cycle. However, discrete projects can arise outside of the Company's normal budget process. In order to account for these projects that arise outside of the normal budget process, the Company reviews historical spend and will place funding in a working capital fund. These working capital funds appear in the routine project lists provided in my Direct Testimony.

Q. IN GENERAL, HOW DOES THE COMPANY DETERMINE COST ESTIMATES FOR INDIVIDUAL DISCRETE PROJECTS?

A. Public Service uses industry-leading practices for budgeting and planning for its projects that align with American Association of Cost Engineers ("AACE") standards. To manage the scope and costs of its projects, the Company governs its investments using a Stage Gate process. The Stage Gate methodology is a scalable process intended to apply increasing rigor and consistent governance throughout the lifecycle of the project. In each Stage, the Company performs a particular scope of work necessary to bring the project to the next Gate, or milestone, that determines whether and how the project will proceed. The estimating process increases in rigor as the project matures and reaches each of the Gates, because the scope of a project becomes more firm and detailed as the project moves closer to implementation and then completion.

The Stage Gate process, designed in concert with AACE principles and aligned with AACE cost estimation standards, has several benefits for project management, and for our customers. First, it demonstrates a formalized manner of managing projects that aligns with industry leading practices and standards. Second, it explains from an objective industry perspective why individual projects will have varying degrees of cost certainty at different points in the process (consistent with AACE International Recommended Practices 97R-19 – Cost Estimate Classification System – As Applied in Pipeline Transportation Infrastructure Projects). For example, permitting requirements, restoration requirements, field conditions, and other circumstances have an unpredictability that can impact the initial estimate, scope, and timing of any particular piece of work. Given this unavoidable fact, the Company believes it is valuable to apply established practices and procedures to manage the work. Third, it illustrates that projects receive detailed scrutiny from multiple angles.

Q. WITH THAT BACKGROUND, CAN YOU PROVIDE ADDITIONAL SUPPORT FOR THE GAS OPERATIONS CAPITAL INCLUDED IN THIS RATE CASE?

A. Yes. In Sections III, IV, V, and VI of my Direct Testimony, I will walk through each of the four areas of investment (Safety, Reliability, New Business, and Mandated Relocations), identifying in more detail how they affect the operations of Public Service's gas system. I will also walk through key capital projects, and provide project-specific attachments for larger projects, supporting the vast majority of individual Gas Operations capital projects and programs included in the cost of service presented by Company witness Mr. Arthur P. Freitas.

III. SAFETY OF THE GAS SYSTEM

Q. WHAT ARE THE KEY COMPONENTS OF MAINTAINING THE SAFETY OF THE PUBLIC SERVICE GAS SYSTEM?

A. As discussed by Company witness Mr. Litteken, customer, system, and public safety are at the core of the mission of Public Service's Gas business. Maintaining safety requires a multi-faceted approach that considers the complex nature of the system and the multiple risks that face any natural gas system. Much of the safety work is focused on maintaining the integrity of the Public Service gas system assets so they can function as intended and provide safe and reliable service to customers. In addition to overall integrity efforts, key safety capital investments I address in this section of my Direct Testimony include the Safety/PSIA category and the Safety/Non-PSIA category.

A. Safety/PSIA

Q. PLEASE DISCUSS THE SAFETY/PSIA INVESTMENT SINCE THE 2019 HTY THROUGH THE 2022 CTY.

A. The Company has had a PSIA rider for Safety/PSIA investment since it was originally approved in 2012. In early 2021, the Company sought to extend the PSIA a final time, through 2024. However, as explained in more detail by Mr. Berman and Mr. Litteken in their Direct Testimonies, the PSIA ceased to exist as of January 1, 2022, in accordance with the process set forth in the 2021 PSIA Settlement. While Attachment JHZ-1 contains actual PSIA capital investment through June 30, 2021 (and forecasted PSIA investment through December 31, 2021), all of the investment through 2020 has already been through a prudence review and true-up process. The 2021 PSIA Projects were filed in Proceeding No. 20AL-0503G and will be subject to a prudence review and true-up process through April 2022 filings required by the 2021 PSIA Settlement.

Q. WHY THEN IS THERE SAFETY/PSIA INVESTMENT IN THE 2022 CTY?

A. Under the 2021 PSIA Settlement, the Company was authorized to implement a one-year PSIA deferral mechanism ("PSIA Deferral") effective January 1, 2022, allowing for $143.1 million of "PSIA" investment in 2022 for the following Distribution Integrity Management Program ("DIMP") Projects: PPRP – Coupled Intermediate Pressure and Vintage Steel and Accelerated Main Replacement Program; and the following Transmission Integrity Management Program ("TIMP") Projects: Automatic Shut-off Valves/Remotely Controlled Valves, Maximum Allowable Operating Pressure, and Pipeline Assessments and Repairs (collectively, "PSIA Projects"). Detail on the 2022 PSIA Projects, including the risk ranking criteria used for PSIA eligibility and budget determinations, was filed with the Commission in Proceeding No. 21A-0071G on November 15, 2021, as required by the 2021 PSIA Settlement. A copy of this filing is attached hereto in support of the 2022 Safety/PSIA capital investment as Attachment JHZ-2.

Q. IF THE PSIA ENDS IN 2021 AND THE PSIA DEFERRAL IS ONLY FOR 2022, WHY ARE YOU PROVIDING INFORMATION ON SAFETY/PSIA CAPITAL FOR 2023 AND 2024?

A. While the Company is only expressly authorized to expend $143.1 million on PSIA Projects in 2022 under the 2021 PSIA Settlement, capital expenditures in 2023 and 2024 are still forecasted for the PSIA Projects in those years, at the reflected amounts. Thus, while there will be no "PSIA" rider or deferral in 2023 or 2024, we provided the forecasted "PSIA Project" capital additions reflected in Table JHZ-D-1 above (and as further detailed in Attachment JHZ-1 to my Direct Testimony) in order to illustrate the impact on the base revenue requirement.

B. Safety/Non-PSIA

Q. PLEASE PROVIDE AN OVERVIEW OF THE SAFETY/NON-PSIA CAPITAL ADDITIONS BETWEEN ROUTINE AND DISCRETE PROJECTS.

A. While many of our capital investments in safety remain in the Safety/PSIA category, as discussed above, Table JHZ-D-2 below identifies the Safety/Non-PSIA plant additions that the Company has invested in, outside of the PSIA, since the 2019 HTY and forecasted through December 31, 2022.

Table JHZ-D-2
Gas Operations Safety/Non-PSIA Capital Additions
Routines vs. Discrete Projects ($ millions)

Safety/Non-PSIA	Actual Additions 10/1/2019 - 6/30/2020	2021 HTY Actual Additions 7/1/2020 - 6/30/2021	Forecasted Additions 7/1/2021 - 12/31/2021	2022 CTY Forecasted Additions 1/1/2022 - 12/31/2022
Routines*	-	-	-	-
Discrete	$7.8	$7.4	$9.8	$9.8
Total	**$7.8**	**$7.4**	**$9.8**	**$9.8**

** There are no Routine capital additions*

Q. PLEASE IDENTIFY THE INDIVIDUAL DISCRETE SAFETY/NON-PSIA PROJECTS IN THIS CATEGORY THAT WERE ADDED BETWEEN OCTOBER 1, 2019 AND JUNE 30, 2021.

A. Table JHZ-D-3 below lists the key discrete Safety/Non-PSIA projects that were in-serviced between October 1, 2019 through June 30, 2021. In addition, the table provides a brief description of each of these safety projects.

Table JHZ-D-3
Discrete Safety/Non-PSIA Plant Additions October 1, 2019 through June 30, 2021 ($ millions)

Project Name	Actual Additions 10/1/2019 - 6/30/2020	2021 HTY Actual Additions 7/1/2020 - 6/30/2021	Description
Tools and Equipment	$6.0	$0.9	Tools and equipment for construction and maintenance activities
CO/EAST/Replace compressor cooler	-	$2.4	Replace three coolers at Roundup
Capitalized Locating Costs	$0.7	$0.9	Capitalized component of damage prevention locates
CO/Silverthorne/Pipeline Marker Install	-	$1.8	Installing approximately 12,000 Light Detection and Ranging (LIDAR) caps
Safety/Non-PSIA - Other	$1.1	$1.3	Various activities to support safety/non-PSIA
Total Safety/Non-PSIA Discrete	**$7.8**	**$7.4**	

**Any differences in sums due to rounding*

Q. PLEASE DESCRIBE THE DISCRETE SAFETY/NON-PSIA PROJECTS THAT ARE BEING ADDED FROM JULY 1, 2021 THROUGH DECEMBER 31, 2021 AND FOR THE 2022 CTY.

A. Table JHZ-D-4 below lists the key discrete Safety/Non-PSIA projects that will be in service between July 1, 2021 and December 31, 2021 and for the 2022 CTY. In addition, the table provides a brief description of each of these safety projects.

Table JHZ-D-4
Discrete Safety/Non-PSIA Plant Additions
July 1, 2021 through December 31, 2022 ($ millions)

Project Name	**Forecasted Additions 7/1/2021 - 12/31/2021**	**2022 CTY Forecasted Additions 1/1/2022 - 12/31/2022**	**Description**
Tools and Equipment	$1.2	$0.5	Tools and equipment for construction and maintenance activities
Above Ground Facility Protection	$0.4	$1.5	Install protection at above ground facilities that have a risk of vehicular damage.
Enhanced Leak Survey – Underground Repair	-	$2.9	Finding and repairing leaks
Replace Station Controls	$1.2	-	Station Control replacements in the West and East divisions
Replace Unit Controls	$1.0	-	Unit Control replacements in the West and East divisions
CO/EAST/Replace compressor cooler	$0.5	-	Replace three coolers at Roundup
Capitalized Locating Costs	$0.3	$2.3	Capitalized component of damage prevention locates
CO/Additional Filtration at Roundup	$1.1	-	Installation of filtration equipment at Roundup
CO/Silverthorne/Pipeline Marker Install	$0.2	$2.0	Installing approximately 12,000 Light Detection and Ranging (LIDAR) caps
Safety/Non-PSIA - Other	$3.8	$0.6	Various activities to support safety/non-PSIA
Total Safety/Non-PSIA Discrete	**$9.8**	**$9.8**	

**Any differences in sums due to rounding*

Q. CAN YOU PROVIDE SUPPORT FOR THE KEY DISCRETE SAFETY/NON-PSIA INVESTMENTS MADE BETWEEN OCTOBER 2019 AND THE END OF THE 2022 CTY FOR PUBLIC SERVICE'S GAS SYSTEM?

A. Yes. Above I have identified the capital additions of the work completed and ongoing in each of these key areas of safety investment, along with descriptions of the work performed in each area. Below, I further discuss key areas of Safety/Non-PSIA investment during the period October 1, 2019 through the 2022 CTY with aggregate capital investment greater than $3 million as well as the Enhanced Leak Survey - Underground Repair Project, explaining why this work is important for the system and necessary to provide safe natural gas service to customers.

1. Tools and Equipment

Q. CAN YOU PROVIDE INFORMATION RELATED TO THE CAPITAL ADDITIONS FOR THE TOOLS AND EQUIPMENT BUDGET CATEGORY?

A. Yes. The Tools and Equipment capital additions of $6.9 million for the period October 1, 2019 through June 30, 2021 included a large order of tools received in late 2019 to support the blowing gas policy including drilling, line stopping, squeeze-jack, and plugging equipment. The referenced 2019 order of blowing gas tools was needed to replace existing tools and purchase additional tools to enable compliance with the Company's then-new blowing gas policy. In compliance with industry best practices, the Company requires, when safely feasible, gas response repair crews to shut off gas remotely instead of entering a blowing gas situation. During the period July 1, 2021 through the 2022 CTY, acquisition of tools for new blowing gas policy compliance normalizes, with capital additions forecasted at $1.7 million during that time period. For the 2022 CTY in particular, the $0.5 million for the Tools and Equipment project is for routine purchases. Tools and Equipment are acquired in support of various operations per 49. C.F.R. Part 192. The Company cannot perform its gas system safety obligations without appropriate tools, such as gas detection equipment, squeeze-off tools, air compressors, and air hammer drills, which are necessary to safely support general operations.

2. Capitalized Locating Costs

Q. WHAT ARE CAPITALIZED LOCATING COSTS?

A. The Company has a Damage Prevention Program, through which we incur costs when necessary to identify and locate/mark where existing underground gas infrastructure exists in order to ensure that other excavation or construction work does not interfere with gas pipelines and create public safety risks. While most of our Damage Prevention costs are O&M, a portion of locate requests each year are performed for Public Service capital projects for new business, main renewals, and capacity projects. The costs for these locate requests are capitalized locate costs. During the period October 1, 2019 through the 2022 CTY, the Company forecasts capital additions of approximately $4.2 million for capitalized locate costs.

3. Transmission Pipeline Marker Install

Q. WHAT IS THE TRANSMISSION PIPELINE MARKER INSTALL PROJECT?

A. Transmission Pipeline Markers are required under code at road crossings, streams/river crossings and within line of sight of another marker. The Company is installing approximately 12,000 Light Detection and Ranging (LIDAR) caps on existing pipeline markers as well as replacing missing or damaged pipeline markers as necessary on approximately 2,000 miles of Gas Transmission pipelines. The Transmission Pipeline Marker Install project will enhance the safe operation of the system by providing the ability to map the locations aerially and identify underground facilities at critical areas of activity where damage by third parties is more likely to occur. In addition, in the event of asset damage, the line markers provide better visibility of assets to Company employees when they are not visible, such as when they are covered by snow. During the period October 1, 2019 through the 2022 CTY, the Company forecasts capital additions of approximately $4.0 million for the Transmission Pipeline Marker Install project.

4. Enhanced Leak Survey – Service Renewals

Q. PLEASE DISCUSS THE COMPANY'S LEAK SURVEY PROGRAM AND ITS IMPORTANCE TO BOTH PUBLIC SAFETY AND METHANE EMISSIONS REDUCTION.

A. In 2020, the Company took steps to enhance the leak survey program and leak management practices by moving from a five-year to a three-year survey cycle, which was agreed to by the parties to the 2020 GRC Settlement and approved by the Commission. The shortened cycle allows the Company to be more efficient in the execution of its survey programs through alignment with atmospheric corrosion inspections at the same interval. As part of this acceleration of leak survey, we have identified several non-hazardous leaks on service valves that are below ground that need to be remediated.

Q. PLEASE DESCRIBE THE COMPANY'S FINDINGS ON SERVICE VALVES.

A. The service valve has a primary function to turn gas on or off to a customer's premise. An above ground service valve is essential for public safety and allows Company personnel during an emergency situation such as fires, leaks, or situations where the gas service needs to be disconnected from the customer's premise. When a buried service valve is identified, the service valve is not accessible during an emergency. Therefore the valve and service line needs to be replaced. Based on preliminary leak survey information from 2020 and 2021, Company personnel have identified approximately 5,000 buried service valves as of October 2021. Service valves can become buried at older homes where elevation changes and additional landscaping or remodeling takes place. In some instances, concrete or other structures have been added near or around the service valve, burying it. Some vintage service valves may be buried due to older installations and settling.

Q. PLEASE PROVIDE INFORMATION RELATED TO THE CAPITAL ADDITION REQUESTED BY THE COMPANY AS RELATED TO THE ENHANCED LEAK SURVEY – SERVICE RENEWALS.

A. The Company targets repairing 1,000 of these buried service valves and services in 2022. The approximate average cost to renew these buried services is $3,000.

Consistent with industry peers, the Company views remediating identified leaks as fundamental to public safety and reducing the impact of methane on the environment. Given the importance of the work under both code requirements and protecting the overall safety of our customers the repairs need to occur and the costs associated with it should be found to be reasonable. Repairing leaks ensures and improves the safety and reliability of Public Service's natural gas system.

5. Safety/Non-PSIA - Other

Q. PLEASE DISCUSS THE SAFETY/NON-PSIA – OTHER PLANT ADDITIONS MADE BY THE COMPANY FROM OCTOBER 1, 2021 THROUGH DECEMBER 31, 2022.

A. While the above safety discussion addresses the large majority of non-PSIA safety-related capital investments since the 2019 HTY, the Company has also in-serviced approximately $2.4 million of other non-PSIA safety plant additions between the end of the 2019 HTY and June 30, 2021, and expects to in-service approximately $4.4 million of other non-PSIA safety plant additions from July 1, 2021 through the end of 2022. Detail regarding the individual components of Non-PSIA - Other safety plant additions are identified and described in Attachment JHZ-3 to my Direct Testimony. This attachment identifies the individual "Other" investments by time period since the 2019 HTY in the 2020 Combined Gas Rate Case, and further describes each individual investment – many of which are under $50,000.

IV. RELIABILITY OF THE GAS SYSTEM

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In the following section of my Direct Testimony, I discuss the Company's work to maintain system reliability for our customers. I begin by explaining our approach to capacity and reliability planning, ensuring a holistic approach that will serve the heating needs of Colorado customers in the immediate years ahead and appropriately for the future. I then support the capital associated with Reliability projects and programs since the 2019 HTY, including a discussion of several discrete capital Reliability projects that will be completed by the end of the 2022 CTY and providing support for the routine work Public Service undertakes to manage the health of system assets and smaller, localized capacity constraints.

A. Public Service's Capacity Planning

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I describe the Company's planning process for capacity projects.

Q. PLEASE DESCRIBE HOW THE COMPANY DETERMINES THE NEED FOR A SPECIFIC GAS CAPACITY PROJECT.

A. The Company's Gas system is modeled and designed to ensure reliable service can be provided to firm gas customers on a Design Day. Design Day temperature is based on the 1-in-30 year low temperature in a given area. Specifically, Public Service uses an industry standard hydraulic modelling software called Synergi® Gas (from DNV GL) to model its gas systems. Each year, the gas engineering team calibrates the hydraulic models with system operating data from the previous heating season to confirm whether the gas system is continuing to meet our system-specific Design Day specifications. This calibration accounts for load changes, changes in system parameters such as piping sizes, new customer additions, energy efficiency, and the removal of customers who have left the system. If system modeling determines that there will be insufficient pressure on a portion of the Company's gas system during a Design Day, the engineer evaluates options to increase pressure and remediate the capacity constraint.

Q. CAN YOU EXPLAIN FURTHER WHAT YOU MEAN BY DESIGN DAY?

A. Yes. The term "Design Day" is referring to the design day temperature, which is the lowest daily temperature a system is expected to see, corresponding to the highest hourly flow rate. The Company utilizes the concept of a Design Day to determine peak hourly flow conditions, ensuring the system is designed to maintain reliable service during cold weather events. Designing a gas distribution system based on this Design Day concept is standard utility practice and recognizes that gas demand is correlated to the ambient temperature. Therefore, as temperatures decrease, the demand for gas increases and system pressures decrease as customers use gas and gas is removed from the pipes. The colder the weather gets, the more the operating pressure within the system is reduced as a result of increased firm customer gas consumption. Inadequate pressures in the gas system can cause interruption in gas service to our firm customers; the system is not designed or built to serve interruptible customers on a Design Day.

Q. HOW IS THE DESIGN DAY DETERMINED?

A. Design Day is determined based on the concept of a peak-day, which refers to an industry standard probabilistic modeling approach to determine the incidence of a 1-in-30 year cold weather event (i.e., "peak-day") occurring. Because temperatures can vary across different geographical areas and different portions of the Company's distribution system within its service territory, the Company's service territory is divided geographically into twelve weather zones across the state based on historical common weather patterns. For example, the 1-in-30 year peak-day minimum temperature for the Denver metropolitan area is -25°F.

Q. WHAT ROLE DOES THROUGHPUT PLAY IN DETERMINING CAPACITY NEEDS?

A. Throughput refers to the volumetric amount of gas that actually flows through a gas pipeline system per unit of time (e.g., hourly, daily, or annually). Because the majority of the Company's gas throughput is used for heating in winter months, the highest load (and therefore the highest throughput) on the system occurs during the coldest days of the year. This is why capacity reinforcement projects must be designed for the peak-day minimum temperature (the Design Day), even though throughput will only approach capacity limits on the coldest days of the year. For the same reason, reductions in overall firm gas load and/or reduction of overall gas system throughput over the year will not eliminate the need for a capacity project designed to meet the specific Design Day parameters for firm customers.

Q. HOW DO STATEWIDE GOALS REGARDING GAS ENERGY EFFICIENCY, AND BENEFICIAL ELECTRIFICATION FACTOR INTO CAPACITY PLANNING?

A. As discussed earlier, each year the hydraulic models are calibrated with system operating data from the previous heating season to confirm whether the gas system is continuing to meet Design Day specifications. This calibration accounts for, among other things, load changes, including those realized through customer adoption programs such as DSM.

Q. DOES THE COMPANY ALSO CONDUCT ONGOING MONITORING OF ITS SYSTEM TO PROVIDE RELIABLE SERVICE TO CUSTOMERS?

A. Yes. Public Service, like most utilities across the United States, monitors its gas system through a Supervisory Control and Data Acquisition ("SCADA") system. This SCADA system collects real time data from across the Company's gas system and converts it into useful, actionable data that is used in our Gas Control center. Here, Gas Controllers review such data as flow rates, pressures, and equipment statuses to make informed decisions ensuring proper system operation. Staffed 24 hours a day, seven days a week, Public Service's Gas Controllers proactively manage the system and identify problems as they arise (e.g., pressure drops/surges, odorization levels, and gas flow rates) and can make changes to the system through the SCADA program or by dispatching field personnel. Public Service's SCADA system has the capability to remotely monitor and control the flow of natural gas into and throughout our transmission and distribution systems. As the Company continues to enhance these capabilities, it has increasing ability to improve the safety and reliability of the system. I discuss our SCADA program in more detail later in my Direct Testimony.

B. System Reliability and Capacity Capital Additions

Q. PLEASE PROVIDE AN OVERVIEW OF PUBLIC SERVICE'S SYSTEM RELIABILITY AND CAPACITY CAPITAL ADDITIONS THROUGH DECEMBER 31, 2022, AS BETWEEN ROUTINE AND DISCRETE PROJECTS.

A. Table JHZ-D-5 below identifies the plant additions that the Company has invested in for reliability and capacity purposes since the 2019 HTY and forecasted through December 31, 2022.

Table JHZ-D-5
Gas Operations Reliability Capital Additions
Routines vs. Discrete Projects ($ millions)

Reliability	Actual Additions 10/1/2019 - 6/30/2020	2021 HTY Actual Additions 7/1/2020 - 6/30/2021	Forecasted Additions 7/1/2021 - 12/31/2021	2022 CTY Forecasted Additions 1/1/2022 - 12/31/2022
Routines	$36.2	$55.0	$23.9	$72.8
Discrete	$42.4	$98.2	$86.5	$62.2
Total	**$78.6**	**$153.1**	**$110.4**	**$135.0**

** Differences in sums due to rounding*

Q. PLEASE IDENTIFY THE INDIVIDUAL DISCRETE RELIABILITY PROJECTS IN THIS CATEGORY THAT WERE ADDED BETWEEN OCTOBER 1, 2019 AND JUNE 30, 2021.

A. Table JHZ-D-6 below lists the key discrete Reliability projects that were in-serviced between October 1, 2019 through June 30, 2021. In addition, the table provides a brief description of each of these Reliability projects.

1 **Table JHZ-D-6**
Discrete Reliability Plant Additions October 1, 2019 through June 30, 2021 ($ millions)

Project Name	Actual Additions 10/1/2019 - 6/30/2020	2021 HTY Actual Additions 7/1/2020 - 6/30/2021	Description
Tungsten to Blackhawk Pipeline Reinforcement**	$1.7	$45.4	Installation of two miles of 6" high pressure main and 13 miles of 8" high pressure main to reinforce Idaho Springs, Black Hawk, Central City, Empire, and Georgetown areas.
Granby T-O to YMCA VS 6"**	-	$13.7	Installation of ~five miles of 6" high pressure main between Fraser and Tabernash.
CO/GJ/ River Road, W-55-A Reif TME**	$8.9	-	Install two miles of 8" high pressure main along River Road in Grand Junction.
CO/Ft Lupton/Ione NF-18 Reinforcement**	$7.9	-	Install 1,700’ of 2” high pressure main and 5,300’ of 4” IP main in the Ft. Lupton area.
F-400 Install New IP Main**	$6.6	-	Install 11,000’ of 6” IP main in Morrison.
CO/Lyons/EL-24 Reinforcement**	-	$5.7	Install approximately 6,400’ of 6” IP main.
Failed Meter Lots	-	$5.3	Multi-year program, exchanging meters identified within failed lots.
CO/Reinforce Rifle with 4" PE and 2**	$3.2	$0.3	Installation of 410' of 2" distribution main and 9,000' of 4" distribution main in Rifle.
CO/East/F-997 Reg Station**	-	$3.0	Replaced regulator station, renamed to F-997 (from F-523).
CO/Tri-Town Interconnect VS Repair**	-	$2.9	Move flanged valves above grade.

Project Name	Actual Additions 10/1/2019 - 6/30/2020	2021 HTY Actual Additions 7/1/2020 - 6/30/2021	Description
SWMR/MCC/LAK/6300 W 13TH AVE/GD**	-	$2.1	Reinforce with 2,651' of 8", 1,353' of 4", 141' of 2" PE main to serve a new 293 unit apartment building coming onto the system.
CO/SEMR/F481 & F872/ IP Reinforce**	$1.9	$0.1	Install a new high pressure to IP regulator station in Aurora.
CO/DMO/Stn 165/Rebuild/Mains	$0.8	$1.1	Rebuild of regulator station in Denver.
CO\PBLO\Reinforce pipe feeding X-31	$1.6	$0.0	Installation of 1,600' of 4" IP into X-31 in Pueblo.
CO/Salida/Marshall Pass shallow HP	-	$1.3	Remediate shallow pipeline road crossings to safely allow fully loaded (85,000#) logging truck traffic.
CO/Bldr/E-119 Reinforcement	$1.2	-	Installation of 2,200’ of 6” IP main in Boulder.
Chalk Bluffs Filter Sep Upgrade	-	$1.1	Filter separator upgrade for increased capacity and reliability.
CO/SEMO/2100-2400 S Clayton St Main	$1.0	-	Install 2,000' of 2" MW main with 4" PE main.
CO/MNTN/BRECK/Breck enridge Reinforcement**	-	$0.1	Installation of seven reinforcements in the Breckenridge area.
Reliability - Capacity	$1.5	$0.9	Various projects to support system capacity.
Reliability - Other	$6.0	$15.4	Various projects in support of system reliability
Total Reliability Discrete	**$42.4**	**$98.2**	

** Differences in sums due to rounding*

*** Project has one page attachment providing more information in Attachment JHZ-4*

Q. PLEASE DESCRIBE THE DISCRETE RELIABILITY PROJECTS THAT ARE BEING ADDED FROM JULY 1, 2021 THROUGH DECEMBER 31, 2021 AND FOR THE 2022 CTY.

A. Table JHZ-D-7 below lists the key discrete Reliability projects that will be in service between July 1, 2021 and December 31, 2021 and for the 2022 CTY. In addition, the Table provides a brief description of each of these Reliability projects.

Table JHZ-D-7
Discrete Reliability Plant Additions July 1, 2021 through December 31, 2022 ($ millions)

Project Name	Forecasted Additions 7/1/2021 - 12/31/2021	2022 CTY Forecasted Additions 1/1/2022 - 12/31/2022	Description
Failed Meter Lots	$13.2	$18.7	Multi-year program, exchanging meters identified within failed lots.
Upsize pipe for Boulder 285#**	$11.7	-	Install approx.11,400’ of 12” HP main in Broomfield.
CO/Del Norte Compressor Station – A**	-	$7.2	Install a second, redundant compressor with driver, cooler and controls at the Del Norte Station.
CO/Rifle/Questar Supply**	-	$5.6	This is a supply project designed to ensure delivery of gas from Questar to the Company. Project includes interconnect with Questar, custody transfer, Xcel-side metering. Re-commissioning of Rifle Compressor Station. Modifications to inlet of Rifle Gas Plant to handle gas supply of varying content and quality.

Project Name	Forecasted Additions 7/1/2021 - 12/31/2021	2022 CTY Forecasted Additions 1/1/2022 - 12/31/2022	Description
CO/Winter Park/Winter Park Tie**	$11.2	$3.8	Install 1.3 miles of 6" HP pipeline via open trench and tie in to existing parallel 6" and 2" HP lines together. Relocation of a total of 1,550 ft. of existing 2" HP pipeline, using 4" HP main as replacement. Replace regulator station RH-1 Hideaway Park. Installation of remote control valve sets and receiver at RH-1 location.
CO/DMO/Rebuild F-392 - CHER & CITY**	$4.3	-	Installation of a new Remote Terminal Unit and rebuild regulator station at F-392.
CO/SEMR/Rebuild 125-E, 125-P, 125-Q**	$6.4	-	Replace/rebuild regulator station 125 - consists of four stations: 125-E, 125-P, 125-Q, 125-Y.
CO/NMR/Rebuild F-340-A and F-340-T**	-	$4.0	Rebuild of the entire regulator station serving the Thornton and Arvada West IP system.
CO/DMR/Rebuild F-524**	-	$4.0	Rebuild of regulator station in Southeast Denver.
CO/AKA/Rebuild Interconnect Install**	$3.3	-	Project includes acquiring land to expand existing site, decommissioning/removing old equip. and installation of a new interconnect and building at AKA.
CO/MNTN/BRECK/Breckenridge Reinforcement**	$3.1	-	Installation of seven reinforcements in the Breckenridge area.

Project Name	Forecasted Additions 7/1/2021 - 12/31/2021	2022 CTY Forecasted Additions 1/1/2022 - 12/31/2022	Description
CO/SWMO/RS F-971**	$2.8	-	Installation of a new regulator station to feed a new development in Littleton, CO.
CO/EAST/Replace Switchgear/VFD Yosemite**	$2.4	-	Yosemite Compressor Electrical Switchgear and Variable Frequency Drive Replacement.
96th & Highway 2 Reg Station**	$0.0	$2.0	Install a new dual run regulator station in the yard at the 96th & Highway 2 regulator station located in Commerce City.
CO/MNTN/RV-7 Reinforcement	$1.7	$0.0	Installation of approx. 1,400 ft. of 6" PE main, installation of 1,550 ft. 4" PE main, installation of approx. 500 ft. of 2" PE main in Vail.
RA-14_RA-20 Line Heaters	$0.0	$1.7	Install line heaters at regulator stations RA-14 and RA-20. Install clamshell heaters at regulator stations RA-16, 17, 19, 23, 24.
CO/SEMR/F715/Inlet Reinforcement	$1.3	$0.0	Installation of 1,100’ of 4” high pressure main in Centennial.
CO/MNTN/Avon Reinforcement	$0.0	$1.3	Reinforce 3,900 ft. of existing 4" main with new 6" PE main in Metcalf Rd.
New Castle WN-1 System capacity reinforcement Ph 2	$0.0	$1.3	Reinforcement consists of upsizing 7,200 ft of 2" main with 4" main in New Castle, CO.
CO/SWMR/Rebuild F-578	$1.0	$0.2	This project focuses on rebuilding F-578.
CO/Upgrade Tiffany Compressor Station	$0.0	$1.1	Replace three Controller units.

Project Name	Forecasted Additions 7/1/2021 - 12/31/2021	2022 CTY Forecasted Additions 1/1/2022 - 12/31/2022	Description
CO/GJ/ River Road, W-55-A Reif TME**	$0.6	$0.0	Increase the capacity of W-55-A by rebuilding of station to accommodate load.
Granby T-O to YMCA VS 6"**	$0.5	$0.0	Completion work of the high pressure main between Fraser and Tabernash.
CO/Salida/Marshall Pass shallow HP	$0.2	$0.0	Completion work to remediate shallow pipeline road crossings to safely allow fully loaded (85,000#) US Forest Service logging truck traffic.
Reliability - Capacity	$3.3	$1.9	Various projects to support system capacity
Reliability - Other	$19.7	$9.3	Various projects in support of system reliability
Total Reliability Discrete	**$86.5**	**$62.2**	

** Differences in sums due to rounding*
*** Project has one page attachment providing more information in Attachment JHZ-4*

Q. CAN YOU PROVIDE MORE INFORMATION ABOUT THE COMPANY'S RELIABILITY CAPITAL PROJECTS?

A. Yes. Attachment JHZ-4 contains project-specific information for each of the capacity projects listed in Tables JHZ-D-6 and JHZ-D-7 that are $2 million or higher (also denoted with a **). In addition, in the next segments of my Direct Testimony, I discuss the discrete capacity projects in these periods with greater than $10 million in capital, as well as the Failed Meter Lot program, Reliability-Capacity, and

Reliability-Other. Finally, I discuss the routine Asset Health and Capacity investment categories.

C. Key Reliability Projects Since the 2019 HTY Through the 2022 CTY

Q. WHICH DISCRETE CAPACITY PROJECTS ARE YOU DISCUSSING IN THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I provide more information on the following projects which are greater than $10 million in capital additions: Tungsten-to Blackhawk, Granby T-O to YMCA VS 6-inch, Upsize Pipe for Boulder 285#, and CO/Winter Park/Winter Park Tie.

1. Tungsten-to-Blackhawk Project

Q. PLEASE PROVIDE AN OVERVIEW OF THE TUNGSTEN-TO-BLACKHAWK RELIABILITY PROJECT.

A. Overall, the Tungsten-to-Blackhawk project is a pipeline project needed to meet growing capacity needs and ensure that the Company can meet peak hour design day requirements. The need for this project was identified during the normal annual process of gas system modeling in 2013. The Company has discussed this Project in several prior gas rate cases, including most recently in the 2020 Combined Gas Rate Case.

The Tungsten pipeline is a 6-inch and 8-inch pipeline that is designed to reinforce the high-pressure ("HP") gas supply to the communities of Idaho Springs, Black Hawk, Central City, Empire, and Georgetown. The pipeline provides additional capacity to the Front Range HP systems by better utilizing the existing capacity on the Littleton Lateral for growth in Lakewood, Highlands Ranch, and

Littleton in southwest Denver. The pipeline contains approximately two miles of 6-inch steel pipe and 13 miles of 8-inch steel pipe, of which both sections are planned to operate at an MAOP of 1000 psig. The route is through a very rocky section of the foothills, roughly between the towns of Nederland and Black Hawk. More information on the route, scope, cost, and additional details regarding the project are found in Attachment JHZ-4 to my Direct Testimony.

Q. DID THE COMPANY CONSIDER ANY ALTERNATIVE TO THIS PROJECT?

A. Yes. An alternate route was investigated that replaced approximately 18 miles of 8-inch high pressure main with 12-inch high pressure main. This alternate route would have commenced outside of Golden, Colorado terminating west of Evergreen Colorado on Santa Fe Mountain. This alternative was ruled out due to its length and higher estimate of $82 million.

Q. WHEN DID PROJECT CONSTRUCTION BEGIN?

A. The actual construction of the pipeline commenced in the second quarter of 2019 after which the full nature of the rock conditions began to present themselves. The Company tested rock samples in June 2019 as a result of construction challenges, and these tests indicated that the route contained sections of particularly hard gneiss rock. Specifically, the samples showed that the bedrock has a compressive strength of 13,718 psi to 19,648 psi.[7]

[7] In comparison, the typical compressive strength of structural concrete ranges from 4,000 psi to 6,000 psi.

Q. HAS THE TUNGSTEN PIPELINE BEEN COMPLETED?

A. Yes. A portion of the project (approximately $8.2 million) was placed in-service in September 2019. This section of pipe was in-serviced before the winter of 2019/2020 to serve the Dory Hill Station, a supply point to Colorado Natural Gas. The remaining project cost, totaling $47.1 million, was in-serviced in September 2020, for the 2020/2021 heating season. The aggregate final project cost was $55.3 million for this important multi-year project.

Q. WAS THE TUNGSTEN-TO-BLACKHAWK PROJECT BROUGHT FORWARD FOR RECOVERY IN THE COMPANY'S 2020 COMBINED GAS RATE CASE?

A. Yes. As part of the 2020 Combined Gas Rate Case, the Company sought to include the entirety of the Tungsten Project, with an estimated aggregate capital addition of approximately $63.9 million, in base rates. At the time the 2020 Combined Gas Rate Case was filed, the cost estimation and design phases for the portion that had not already been placed in service had been completed, and construction was in progress.

Q. HOW WAS THE COMPANY'S REQUEST TO INCLUDE THE ENTIRETY OF THE TUNGSTEN-TO-BLACKHAW PROJECT IN BASE RATES RESOLVED IN THAT CASE?

A. As mentioned earlier in my Direct Testimony, the 2020 Combined Gas Rate Case was resolved through the 2020 GRC Settlement, which was approved by the Commission. Through that Settlement, it was agreed that a significant portion of the Tungsten Project would be included in base rates. Specifically, the 2020 GRC Settlement provides as follows:[8]

> The Settling Parties agree that the settled revenue requirement shall be calculated based on year-end rate base and incorporate a known and measurable post-Test Year adjustment for the annualized revenue requirement associated with the Tungsten to Blackhawk capital project investment as of April 30, 2020 ("Tungsten"). The Company shall have the right to seek recovery for the remainder of the Tungsten project in a future proceeding.

As a consequence of the foregoing, approximately $44.2 million of the Tungsten capital addition is already included in base rates.[9] Based on the final project cost of $55.3 million, an additional $11.1 million of the capital additions implemented after April 30, 2020 would be recovered for the first time as part of this case, as contemplated by the 2020 Gas Rate Case Settlement.

Q. PLEASE EXPLAIN THE VARIANCE BETWEEN THE AGGREGATE APPROXIMATE $63.9 MILLION COST ESTIMATE AND THE FINAL COST OF $55.3 MILLION FOR THE TUNGSTEN PIPELINE PROJECT.

A. The initial cost estimates for this project were premised on a different pipeline route and contained risk impacts for the potential of hard rock along the Right of Way (ROW) and additional boring costs. Applying lessons learned from construction of the southern portion in 2019, it was determined to try to avoid county roads that would be required to be closed. This led to the re-route of the northern half of the

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[8] 2020 GRC Settlement at p. 10.

[9] Hearing Exhibit 133, Attachment DAB-20 to Company witness Ms. Deborah A. Blair's Settlement Testimony, at Schedule 269, reflects a Plant-in-Service adjustment for the Tungsten project of $36,040,635. Including the approximate $8.2 million capital addition that had been in-serviced during the 2019 HTY, the total Tungsten pipeline project capital addition included in base rates as part of the 2020 Combined Gas Rate Case was approximately $44.2 million.

pipeline, resulting in approximately $2.8 million in direct savings. The change in route also lead to a simplified bore versus what was included in the original estimate. Specifically, instead of multiple bores with both horizontal and vertical components, a single successful bore was completed beneath the Union Pacific Railroad and S. Boulder Creek, resulting in estimated risk funding not being used. Lastly, the initial estimate contained risk funding for hard rock anticipated along approximately 50 percent of the linear pipeline length. This estimate was developed from the engineering pre-work that was mentioned above. Actual hard rock encountered, especially on the northern portion, was significantly less. These primary factors combined with overall effective construction management resulted in the reduction from the initial cost estimate.

2. Granby T-O to YMCA VS 6-inch Project

Q. PLEASE PROVIDE AN OVERVIEW OF THE GRANBY T-O TO YMCA VS 6-INCH PROJECT.

A. The Granby Take-off ("T-O") to YMCA Valve Set ("VS") 6-inch project is a reinforcement of the Company's gas system in the Granby and Grand Lake areas of Colorado. The project installed approximately 4.8 miles of 6-inch HP 1,000 psig pipe from Fraser to Tabernash, Colorado, parallel to an existing 3-inch HP pipe. The project relocated approximately 1,250 feet of the 3-inch HP pipe as part of right-of-way negotiations to parallel the new 6-inch pipe, rebuilt two valve sets, and installed a remote-controlled valve ("RCV"). Additionally, the project included the rebuild and installation of new regulator stations RT-1 at Tabernash and RT-3 at YMCA to accommodate the new 6-inch pipeline. The overall reinforcement project resolved the risk of outages to approximately 2,000 firm customers in the Grand Lake area when temperatures fall to design day temperatures of -39 degrees Fahrenheit.

Q. WHAT ALTERNATIVES TO THE GRANBY T-O TO YMCA VS CAPACITY PROJECT DID THE COMPANY CONSIDER?

A. The Company considered the alternative of reinforcing the upstream pipeline system by reinforcing more than 24 miles of pipelines and crossing the Continental Divide from Kremmling, Colorado. Other potential alternatives considered included supplementing the system from liquified natural gas ("LNG"). The alternative pipeline had an estimated cost of $42 million and was deemed cost prohibitive. Likewise, the LNG facility was cost prohibitive with an initial estimate of $35 million. As noted above, the final Granby T-O to YMCA VS Capacity Project was $13.7 million.

Q. WAS THE GRANBY T-O TO YMCA VS PIPELINE PROJECT COMPETITIVELY BID?

A. Yes. The construction and engineering portions were competitively bid. During the project estimating process, the Company collected competitive bids from multiple vendors and incorporated them into the final estimates. The updated scope, route, and estimate were then vetted by a diverse group of engineers, project managers, sourcing specialists, and leaders prior to the work being released to construction. The project is now in service and providing capacity support to our firm customers.

3. Upsize Pipe for Boulder 285# Project

Q. PLEASE PROVIDE AN OVERVIEW OF THE UPSIZE PIPE FOR BOULDER 285# PROJECT.

A. The Upsize Pipe for Boulder 285# project consisted of replacing 10,200 foot of 6-inch steel pipe with 12-inch steel pipe to reinforce the Broomfield, Colorado system due to new customer growth on the system. When this area of the system was hydraulically modeled to peak hour temperatures, -25 degree Fahrenheit, the model indicated low inlet pressures into the EB-20 regulator station, resulting in potential outages to approximately 5,500 firm residential customers. In fact, outages began to impact customers when area temperatures reached –1 degree Fahrenheit. To prevent these outages, Company personnel took action at EB-20 to increase gas supply whenever temperatures were within 10 degrees of this targeted temperature, that is, when area temperatures were 9 degrees Fahrenheit or less. Over the past two heating seasons, the Company took action at the EB-20 regulator, usually bypassing the station, 40 times. Doubling the pipe diameter from 6-inches to 12-inches increased the inlet pressure to the regulator station to meet the requirements of our firm customer during cold temperatures up to design day temperatures. This project was in-serviced in September 2021.

Q. WHAT ALTERNATIVES TO THE BOULDER 285# PIPELINE PROJECT DID THE COMPANY CONSIDER?

A. The Company considered alternatives including reinforcing piping from another regulator station, EB-6, to EB-10 and changing the system pressure, installing smaller diameter, high-pressure pipe. Under this option, at least three existing regulator stations would have been required to be rebuilt. Due to the complexity, the existing 285# pipe already in the area, and the estimated cost of $17.0 million as compared to the estimated cost for the project of $11.7 million, this option was ruled out.

Q. WAS THE UPSIZE PIPE FOR THE BOULDER 285# PROJECT COMPETITIVELY BID?

A. Yes. The construction and engineering portions were competitively bid in 2020. The Company utilizes a value threshold of $7.5 million for the mechanical construction portion of a project in determining whether the project is direct awarded from a Master Service Agreement ("MSA") or is bid independently outside of the MSA vendors. This project was delayed from 2020 to 2021 due to COVID uncertainties and was ultimately awarded in 2021. Adjustments to the 2020 contract units were made where needed, resulting in a reduction to the final bid price.

4. CO/Winter Park/Winter Park Tie Project

Q. PLEASE GENERALLY DISCUSS THE CAPACITY CONSTRAINTS IN WINTER PARK.

A. The Town of Winter Park was previously served by two pipelines coming from the north, a 2-inch pipeline primarily serving the town, and a 6-inch pipeline that ran a parallel route to the east but connected south of the town, primarily serving the ski resort. As part of the Company's annual planning process in 2018, Company engineers first identified a capacity shortfall in Winter Park for the winter of 2021/2022 to serve firm customers at a design day temperature of -39 degrees

Fahrenheit. As part of the 2019 annual planning process, the 2-inch pipeline was forecasted to be at capacity for the winter of 2020/2021, and would be unable to reliably serve firm customers below -32 degrees Fahrenheit, which had a potential of occurring once every seven years.

Q. CAN YOU PROVIDE MORE INFORMATION REGARDING THE GAS CUSTOMER GROWTH THE COMPANY HAS EXPERIENCED IN GRAND COUNTY, DRIVING THE WINTER PARK CAPACITY CONSTRAINT?

A. Yes. Going back to 2015, Grand County Colorado experienced about a 1.5 percent annual customer count growth rate. This annual growth rate remained stable until 2019 when the growth rate increased by over 70 percent to 2.6 percent and 2.7 percent in 2020. The growth rate in 2021 was 1.9 percent. Although this is less than the growth rates in 2019 and 2020, it was 25 percent higher than the historical stable growth of 1.5 percent. From 2015 to 2021, the gas customer count in Grand County increased by over 12 percent from approximately 9,550 customers to over 10,700 customers.

Q. DID THE COMPANY UPDATE ITS PROJECT PLAN OVER TIME?

A. Yes. Various segments were identified to be reinforced, moved or interconnected, but the key component was to connect the existing 6-inch pipeline to the existing 2-inch pipeline. This solution had particular challenges due to property ownership and required permits for parts of the right of way, which led to the Winter Park Tie reinforcement project needing to be phased in over two years, with Phase 1 going into service a year later than needed and Phase 2 to follow. I describe these phases in more detail below.

Q. WITH THE DELAYED PROJECT IN-SERVICING, HOW DID THE COMPANY SERVE THE REQUIREMENTS OF FIRM CUSTOMERS FOR THE WINTER OF 2020/2021?

A. As part of its annual process, the hydraulic model was updated again in 2020. Without the project going into service or finding a temporary solution for the winter of 2020/2021, the Company determined that up to 350 firm customers could lose gas service once temperatures hit -27 degrees Fahrenheit. Therefore, the Company sited CNG in the Winter Park area during the winter of 2020/2021 to avoid customer outages, though the temperature threshold was never achieved where CNG was required to be used.

Q. PLEASE DESCRIBE HOW CNG IS USED TO HELP SUPPORT THE SYSTEM TO AVOID CUSTOMER OUTAGES.

A. CNG is required to be sited central to the capacity constrained area in order to provide the system with an additional supply source of gas. CNG tanks, de-pressuring equipment, fueling connections, and auxiliary equipment are set at a surface location. When in use, the CNG location would require refueling by transporting large CNG trailers into and out of the location. Refueling is necessary each time the CNG tankers are used. Based on modeling, the use of CNG would begin to be injected into the system at -27 degrees Fahrenheit. CNG is generally not a long-term solution due to the cost and logistics as I describe below; therefore, the Company focused on a more permanent Winter Park reinforcement project.

Q. PLEASE DESCRIBE PHASE 1 OF THE WINTER PARK PROJECT.

A. Phase 1, which was in-serviced in 2021, included a 6-inch reinforcement line, connecting the eastern 6-inch line to the 2-inch pipeline near Hideaway Park which resolved the capacity constraints on the HP 2-inch pipeline . This line was installed with temporary tie-ins to be able to in-service in 2021. In addition to the pipeline tie, relocating a northern portion of the existing 2-inch HP line was necessary to allow for approved, planned developments in the area. This phase is helping the Company meet firm customer needs during the 2021/2022 heating season.

Q. PLEASE DESCRIBE PHASE 2 OF THE WINTER PARK TIE REINFORCEMENT PROJECT.

A. Phase 2, to be completed in 2022, includes completing the 6-inch reinforcement, rebuilding/relocating a regulator station, relocating a southern portion of the existing 2-inch HP pipeline, and finalizing distribution ties/cutoffs. The relocation of the northern and southern portions of the existing 2-inch line, using 4-inch pipe, total approximately 1,500 feet. The regulator station rebuild of RH-1 Hideaway Park was required to accommodate the pipeline upgrades, but is also being relocated as part of an agreement with the developer. The station rebuild also includes the installation of a new in-line assessment tool receiver for integrity management and maintenance purposes.

When both phases are completed, the project will install approximately 1.3 miles of 6-inch HP 1,000 psig pipe to connect the 6-inch and 2-inch high pressure pipelines that serve the Company’s Winter Park system. The project allows for reliable service to firm customers at design day temperatures of -39 degrees

Fahrenheit, resolving outage risks in the Fraser and Winter Park areas. The combined two phases of the project is expected to total $15.0 million, with approximately $11 million in-serviced in 2021 and the remainder to be completed in 2022.

Q. WHAT ALTERNATIVES DID THE COMPANY INVESTIGATE INSTEAD OF CONSTRUCTING THE WINTER PARK TIE REINFORCEMENT PROJECT?

A. The Company evaluated the opportunity to avoid the pipeline investment in this area by converting firm customers to interruptible services, as well as supporting the system with compressed natural gas/liquified natural gas. However, converting firm customers to interruptible service would have required customers to install backup systems to allow curtailment. Additionally, supplementing the system with CNG would have required locating six semi-tankers and additional auxiliary equipment in the area that would need to be used an estimated 18 times per year (108 tanker loads) for the 2021/2022 heating season alone. This estimated injection frequency increases each following year, with CNG operating expenses expected to surpass $3 million per year, not accounting for other operational impacts, by 2030. In addition to cost, such a significant scope of permanent CNG support would involve, at a minimum, land siting issues, public safety issues, and significant security issues; therefore it was not a viable alternative.

Q. WAS THE WINTER PARK TIE PIPELINE PROJECT COMPETITIVELY BID?

A. For the completion of Phase 1, the project was split into two sub-projects for construction. The smaller scope 2-inch relocation portion was a direct award from a Master Service Agreement (MSA), as it was below the $7.5 million threshold for competitive bidding. The larger scope 6-inch reinforcement went to bid. Selection was completed after evaluating pricing, confidence in vendor work plans and chance of successfully in-servicing in 2021. Phase 2 of the project has not yet been awarded but is expected to be Direct Award based on the remaining estimate relative to the established threshold for competitive bidding.

Q. WAS THE WINTER PARK TIE PLACED IN-SERVICE?

A. Phase 1 of the two-phased project was in-service in October 2021 to help meet customer needs during the 2021/2022 heating season, while the remaining 2022 phase will be completed by September 2022.

5. Failed Meter Lots

Q. WHAT IS THE FAILED METER LOT PROGRAM?

A. The Company has a Commission-approved gas meter test sampling program ("Program") and annually provides its meter random sample test results in Proceeding No. 08A-280G. The Program pertains to all installed diaphragm-type gas billing meters.

Q. HOW IS THE FAILED METER LOT PROGRAM CARRIED OUT?

A. The Program uses statistical sampling that generally conforms to the guidelines provided by the American National Standard, Diaphragm-Type Gas Displacement Meters (under 500 Cubic Feet Per Hour Capacity), (ANSI B109.1, Approved April 13, 2000) and Diaphragm-Type Gas Displacement Meters (500 Cubic Feet Per Hour Capacity and Over), (ANSI B109.2, Approved April 13, 2000) and the American National Standard Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming (ANSI/ASQ Z1.9- 2003). In addition, homogeneous meter lots are analyzed, and lots not meeting criteria are examined further under tightened subsequent testing and analysis within a five-year duration. Those meter lots meeting criteria remain under normal inspection. Under tightened inspection, gas meter lots not meeting acceptable accuracy criteria for five consecutive years are identified as a "failed lot" – and are no longer tested.

Q. WHAT IS THE SCOPE OF WORK FOR THE PROGRAM THROUGH THE 2022 CTY IN THIS PROCEEDING?

A. Approximately 280,000 gas meters were in a failed status as of the time the last report was filed and are no longer subject to sampling under the Program. The Company has undertaken a multi-year project to replace these failed meters. This project, which began in the second quarter of 2021, entails exchanging an average of 35,000 meters each year for approximately eight years. Both internal and contractor resources will be executing these exchanges. For the exchanges taking place from July 1, 2021 through the 2022 CTY, the forecasted aggregate capital additions are $31.9 million.

6. Reliability – Capacity

Q. WHAT OTHER RELIABILITY – CAPACITY ADDITIONS HAS THE COMPANY MADE FROM OCTOBER 1, 2019 THROUGH THE 2022 CTY?

A. In addition to the discrete reliability projects mentioned previously, the Company also performs other projects to help ensure system infrastructure reliability to serve Colorado customers. Attachment JHZ-5 to my Direct Testimony includes the project name, capital additions, and description of each of the "Reliability – Capacity" capital additions from October 1, 2019 through June 30, 2021, many of which are under $50,000. Furthermore, the Company is forecasting $3.3 million of plant additions during the last half of 2021 and $1.9 million during the 2022 CTY. Attachment JHZ-5 to my Direct Testimony provides the project name, capital additions, and description of the "Reliability – Capacity" for $5.2 million in plant additions.

7. Reliability – Other

Q. WHAT RELIABILITY - OTHER ADDITIONS HAS THE COMPANY MADE FROM OCTOBER 1, 2019 THROUGH THE 2022 CTY?

A. In addition to the discrete reliability projects mentioned previously, the Company also performs other projects to help ensure system health and reliability to serve Colorado customers. Attachment JHZ-6 to my Direct Testimony includes the project name, capital additions, and description of each of the "Reliability – Other" capital additions from October 1, 2019 through June 30, 2021, many of which are under $50,000. Furthermore, the Company is forecasting $19.7 million of plant additions during the last half of 2021 and $9.3 million during the 2022 CTY. Attachment JHZ-6 to my Direct Testimony provides the project name, capital additions, and description of the "Reliability – Other" for $29.0 million in plant additions.

Q. ARE THERE ANY INDIVIDUAL RELIABILITY-OTHER PROJECTS YOU WISH TO HIGHLIGHT?

A. Yes. In its prior three gas Phase I rate cases, Public Service proposed to increase the number of SCADA pressure monitoring points at regulator stations and other strategic locations on our gas transmission and distribution systems, through a targeted SCADA/Gas Control Monitoring program. Day-to-day, the remote field monitoring devices provide advanced warning of situations and allow an opportunity for Public Service to operate the system from the control room or dispatch crews proactively to make the appropriate adjustments or repairs before they put the public or system at risk. Equally important, a robust SCADA system is crucial for long-term system reliability planning purposes.

In the 2015 Gas Phase I, the Commission stated that to obtain cost recovery related to the SCADA/Gas Control Monitoring program in the future, the Company "must conduct a thorough quantitative cost benefit analysis for project justification for future cost recovery of any additional upgrades."[10] In both the Company's 2017 Gas Phase I and 2020 Combined Gas Rate Case, we provided a program cost-benefit analysis that identified the major system events that were proactively avoided by Gas Control personnel responding to system issues; the likely outages that would have resulted if not for the Company's proactive response; and therefore, the actual costs and benefit of avoided customer outages. In both cases, the results of the cost-benefit analysis illustrated that the Company's SCADA/Gas Control Monitoring program was an effective risk and system issue mitigation tool.

[10] Decision No. C16-0123 at p. 24.

Q. WHAT WORK IN THIS AREA HAS THE COMPANY COMPLETED SINCE THE 2020 COMBINED GAS RATE CASE?

A. As of September 30, 2019, the Company had approximately 1,096 SCADA monitoring devices in the field. As of June 30, 2021, the Company has replaced approximately 12 obsolete monitoring devices and installed 134 additional remote SCADA monitoring devices on its system, for a total of 1,230 devices. However, the SCADA/Gas Control Monitoring program is winding down, with a focus on implementing individualized devices in the field as needed. The costs in this case total approximately $1.1 million, as illustrated on Attachment JHZ-6 to my Direct Testimony.

Q. DID THE COMPANY COMPLETE SUCH A COST-BENEFIT ANALYSIS FOR THIS PROCEEDING?

A. Yes. The Company refreshed its Workbook analysis with actual costs of the SCADA work compared to known benefits resulting from avoiding system events and customer outages, utilizing the same cost-benefit analysis ("CBA") methodology from each of our prior two rate cases. The results of the CBA are included as Attachment JHZ-7 to my Direct Testimony. As reflected therein, in the twenty-one-month period ended June 30, 2021, the Company identified approximately 61 unique events where a potential outage was avoided using information from the 134 field monitoring devices installed between October 1, 2019 and June 30, 2021. The new units helped prevent approximately 35,000 potential customer outages over the twenty-one-month period and required approximately $1.1 million in capital expenditures to install the units. This results in approximately $30 per avoided outage within the observation time period, reducing to $5 per avoided outage over the lifespan of the device. In comparison, the relight cost is approximated at $45 per customer. Given the high risk to public safety inherent in outage events, the result of the analysis is a positive cost benefit.

Q. DOES THE COMPANY HAVE ANY REQUESTS RELATED TO THIS PROGRAM?

A. Yes. In addition to approving the costs of the SCADA program in this proceeding, the Company asks that it no longer be required to conduct a future CBA related to these limited device implementations. Conducting the CBA is resource intensive, especially in relation to the current size of the investments. Should the scale of the program increase substantially, the need for CBAs could be revisited at that time.

D. Routine Asset Health Investments

Q. WHAT ARE ASSET HEALTH ROUTINES?

A. Asset health routines are budgets used to fund routine small Asset Health or compliance projects that are typically less than $300,000. Projects classified under the asset health routines include replacements of failed equipment or leaks that require repair in accordance with the Company's Pipeline and Compliance Manual. Renewals of gas main and services not covered under the PSIA or PSIA Deferral are also included in asset health routines.

Q. HOW DOES THE COMPANY BUDGET FOR ASSET HEALTH ROUTINES?

A. The budget for asset health routines is based on the averages of historical spend levels based on historical infrastructure needs escalated by the corporate inflation rate, also referred to as the corporate escalator. The escalation factors include but are not limited to labor, non-labor, contractor, materials, equipment and fleet inflation rates, and bargaining labor increases. The Company only budgets for known discrete asset health projects if they are identified ahead of budget creation; emerging discrete asset health projects that come up after budget creation utilize funding from the routines.

Q. CAN YOU PROVIDE MORE DETAIL REGARDING THE KINDS OF PROJECTS COVERED BY ASSET HEALTH ROUTINES FROM THE 2019 HTY THROUGH THE 2022 CTY?

A. Yes. The kinds of projects included in the asset health routines are comprised of smaller condition-based main and/or service replacements, leak repairs, removal of services due to structure removal, replacement/removal of services in support of main reinforcements or main relocations, and customer-requested relocation of service due to building modifications. Tables JHZ-D-8 and JHZ-D-9 below reflect the asset health routine plant additions in support of the project types described above, along with the amount of main, in feet, renewed during this time period:[11]

[11] The Company tracks main renewals in feet on an ongoing basis, rather than in terms of plant additions. Therefore, there may be a timing difference with respect to plant additions and feet of main renewed in a given year. This also applies to main reinforcements, new main, and main relocations.

Table JHZ-D-8
Asset Health Routines Plant Additions and Footages
October 1, 2019 to June 30, 2021 ($ millions)

Routine Description	Actual Additions 10/1/2019 - 6/30/2020	2021 HTY Actual Additions 7/1/2020 - 6/30/2021	Total
Service Renewal/Cutoff Additions ($M)	$19.0	$34.0	**$53.0**
Main Renewal Additions ($M)	$7.2	$11.7	**$18.9**
Main Renewal Additions (feet)	22,369	58,062	**80,431**

Table JHZ-D-9
Forecasted Asset Health Routines Plant Additions
July 1, 2021 to December 31, 2022 ($millions)

Routine Description	Forecasted Additions 7/1/2021 - 12/31/2021	2022 CTY Forecasted Additions 1/1/2022 - 12/31/2022	Total
Service Renewal/Cutoff Additions ($M)	$8.9	$42.5	**$51.5**
Main Renewal Additions ($M)	$5.3	$15.2	**$20.5**

** Differences in sums due to rounding*

Q. WHY ARE THE FORECASTED ADDITIONS FOR JULY 1, 2021 THROUGH THE 2022 CTY REASONABLE?

A. As previously discussed, our budgets for asset health routines are based on historical data. From October 1, 2019 through June 30, 2021, the Company's actual plant additions for asset health routines was $71.9 million or $3.4 million per month. From July 1, 2021 through the 2022 CTY, the Company has budgeted $71.9 million in plant or an average of $4.0 million per month. The Company has reasonably forecasted plant additions for the asset health routines based on historical spend escalated by the corporate inflation rate. The July 1, 2021 through 2022 CTY budget includes funding for projects the Company expects to implement through ongoing reliability exchanges and to reflect the likely emergence of related work. This is included to provide flexibility with respect to necessary capital projects that may be identified in the coming year.

E. Routine Capacity Investments

Q. WHAT ARE CAPACITY ROUTINES?

A. Projects included in capacity routines are infrastructure work related to increasing gas main capacity to mitigate low-pressure, customer outage related risks based on design day modeling. This type of work is driven by increased load, either from existing customers or new customers.

Q. HOW DOES THE COMPANY BUDGET FOR CAPACITY ROUTINES?

A. The budget for capacity routines is based on the averages of historical spend levels based on historical infrastructure needs escalated by the corporate inflation rate (also referred to as the corporate escalator), in the same manner as the budget is determined for asset health routines. The escalation factors include but are not limited to labor, non-labor, contractor, materials, equipment and fleet inflation rates, and bargaining labor increases. The Company only budgets for known discrete capacity projects if they are identified ahead of budget creation; emerging discrete capacity projects that come up after budget creation utilize funding from the capacity routines.

Q. CAN YOU PROVIDE MORE DETAIL REGARDING THE KINDS OF PROJECTS COVERED BY CAPACITY ROUTINES FROM OCTOBER 1, 2019 THROUGH THE 2022 CTY?

A. Yes. Capacity routines are comprised of smaller projects involving the replacement of existing main assets with larger diameter pipe. Tables JHZ-D-10 and JHZ-D-11 below reflect the plant additions in support of capacity routines for the project types described above, along with the number of feet of replaced main for the period October 1, 2019 through June 30, 2021.

Table JHZ-D-10
Capacity Routines Plant Additions and Footages
October 1, 2019 to June 30, 2021 ($ millions)

Routine Description	Actual Additions 10/1/2019 - 6/30/2020	2021 HTY Actual Additions 7/1/2020 - 6/30/2021	Total
Main Reinforcement Additions ($M)	$10.1	$9.3	**$19.3**
Main Reinforcement Additions (feet)	18,736	68,076	**86,812**

Table JHZ-D-11
Forecasted Capacity Routines Plant Additions
July 1, 2021 to December 31, 2022 ($millions)

Routine Description	Forecasted Additions 7/1/2021 - 12/31/2021	2022 CTY Forecasted Additions 1/1/2022 - 12/31/2022	Total
Main Reinforcement Additions ($M)	$9.7	$15.1	**$24.8**

Q. WHY ARE THE FORECASTED ADDITIONS FOR JULY 1, 2021 THROUGH THE 2022 CTY REASONABLE?

A. From July 1, 2021 through December 31, 2021, the Company has budgeted $9.7 million in plant additions or an average of $1.6 million per month. For the 2022 CTY, the Company budgeted $15.1 million in plant additions or an average of $1.3 million per month for projects involving the replacement of existing main assets with larger diameter pipe. From October 1, 2019 through June 30, 2021, the Company's actual plant additions for the capacity routines was $19.4 million or $0.9 million per month. The Company has forecasted plant additions for the capacity routines in the 2022 CTY based on the average of historical actuals from 2019 and 2020 escalated by the corporate inflation rate (approximately three percent), which is reasonable.

V. NEW BUSINESS

Q. HOW DOES PUBLIC SERVICE RECEIVE REQUESTS FOR NEW BUSINESS?

A. Public Service receives requests from individuals and developers for new gas service through the Company's Builders Call Line. The Builders Call Line is the customer's first point of contact when requesting new gas and electric service from the Company and is intended to be a single call department to simplify the customer's experience. The Company supports new business customers through five key phases of installing and connecting new service through the Builders Call line: 1) application; 2) design; 3) payment; 4) scheduling; and 5) construction and meter set. The Builders Call Line delineates which tasks within the five phases are the customer's responsibility, the Company's responsibility, and joint responsibility between the customer and the Company.

Q. WHAT IS PUBLIC SERVICE'S OBLIGATION UPON RECEIPT OF REQUESTS FOR SERVICE FROM NEW CUSTOMERS WITHIN THE COMPANY'S SERVICE TERRITORY?

A. Public Service has an obligation to provide natural gas service to new customers within areas in the State of Colorado where the Company has received approval from the Commission to build and operate a gas system. These areas are known as certificated service territories. These territories provide boundaries to gas utilities to ensure that duplicate assets are not built to serve customers. Another advantage to certificated territories is customers and emergency personnel, like fire departments, know which gas utility is responsible for gas odors, gas leaks, and gas line location services.

Q. HOW DOES PUBLIC SERVICE DESIGN, ENGINEER, AND OBTAIN A COST ESTIMATE FOR THE PROJECT ONCE IT OBTAINS A REQUEST FOR NEW BUSINESS?

A. The design phase begins when a customer submits building plans and a request for service to the Company's Builders Call Line. During that initial call, information such as address, customer contact information, building type, and any available load data is collected by the Company and compiled into a standardized form. That data is then assigned to a designer, who will contact the customer and arrange a meeting to cover any specifics related to the project.

After that initial meeting, the designer uses a program called Bentley Expert Designer to start outlining the project scale, route, and required materials to meet the customer's needs. Bentley Expert Designer allows the designer to determine the pipeline route, select the required materials, and factor in installation and restoration costs. If the request for new gas service is large in nature, and served from our HP system, the request for new business is transferred from the designer to a gas engineer. That list of materials and labor is then populated into the Company's Work and Asset Management system and sent to local design and engineering management for review and approval before a quote is issued. From that point, the system generated cost estimates are valid for 90 days before a refresh is required. If the customer accepts the quote by signing the service agreement, payment is collected, and the project is moved to construction.

Since Bentley Expert Designer is built into the Company's Geographic Information System, all location and material information is captured and added to the Company's mapping system and serves as the Company's asset system of record. The design process is the same for both gas and electric and a customer can start the process for both gas and electric services concurrently, with one application.

Q. HOW DOES THE COMPANY DETERMINE IF THE PARTY REQUESTING NEW SERVICE NEEDS TO BE CHARGED CONTRIBUTION IN AID OF CONSTRUCTION?

A. New business customers are subject to the Gas Distribution Extension Policy process as outlined in Public Service's Gas Tariff. The policy was updated in 2019 as part of Commission Proceeding No. 18AL-0826G. That policy determines customer versus Company contributions to new gas main extensions.

Q. HOW ARE NEW BUSINESS PROJECTS ACCOUNTED FOR?

A. All costs associated with new business are capital, including labor and materials. As with other parts of the Gas Operations projects, there are two types of capital project funding types: 1) discrete projects, and 2) routines. Discrete projects typically are more complex projects that may include transmission mains, transmission regulator stations, larger diameter distribution mains, distribution regulator stations, and land or easement purchases. New business discrete projects are tracked individually under separate work orders and have a high likelihood of having expenditures in more than one budget year.

New business projects funded under routines are generally simpler in nature, like a new service and new meter. In any given year the Company receives many requests for new service but cannot necessarily predict exactly when those requests will be received, therefore new services are not defined until the current year.

Q. HOW ARE CONSTRUCTION COSTS TYPICALLY DETERMINED FOR NEW BUSINESS WORK AT PUBLIC SERVICE?

A. New business projects are primarily installed by qualified contractors where the Company has a negotiated MSA with each contractor. These MSAs have per-unit pricing. For example, within the negotiated MSA, the cost per service and the cost to install gas mains is set based on pipe diameter and the required installation technique (e.g., trench, bore, etc.).

Q. HOW MANY NEW NATURAL GAS CUSTOMERS DID PUBLIC SERVICE CONNECT FROM OCTOBER 1, 2019 THROUGH JUNE 30, 2021?

A. From October 1, 2019 through June 30, 2021 Public Service connected 28,963 new natural gas customers, a growth rate of 2.0 percent. Public Service natural gas customer counts increased from 1,422,751 on October 1, 2019 to 1,451,714 on June 30, 2021. Attachment JHZ-8 to my Direct Testimony includes the new natural gas customer counts from October 1, 2019 through June 30, 2021.

Q. WHAT WERE THE RESULTING PLANT ADDITIONS TO SUPPORT THIS AVERAGE ANNUAL NEW CUSTOMER GROWTH?

A. From October 1, 2019 through June 30, 2021 Public Service added $151.0 million in plant additions to support these additional customers and the load growth for existing customers. The Company is forecasting $51.8 million in plant additions from July 1, 2021 through December 31, 2021, and $103.9 million during the 2022 CTY to support the estimated 20,412 new customer connections during this time period. Table JHZ-D-12 below identifies the new business plant additions for discrete and routine projects from October 1, 2019 through December 31, 2022.

Table JHZ-D-12
Gas Operations New Business Capital Additions
Routines vs. Discrete Projects ($ millions)

New Business	Actual Additions 10/1/2019 - 6/30/2020	2021 HTY Actual Additions 7/1/2020 - 6/30/2021	Forecasted Additions 7/1/2021 - 12/31/2021	2022 CTY Forecasted Additions 1/1/2022 - 12/31/2022
Routines	$53.9	$82.6	$36.9	$105.1
Discrete	$5.7	$8.8	$15.0	($1.2)
Total	**$59.6**	**$91.4**	**$51.8**	**$103.9**

**Any differences in sums due to rounding*

Q. PLEASE DESCRIBE THE DISCRETE NEW BUSINESS PROJECTS THAT WERE ADDED FROM OCTOBER 1, 2019 AND JUNE 30, 2021.

A. Table JHZ-D-13 below lists the key discrete new business projects that were in-serviced between October 1, 2019 and June 30, 2021. In addition, the Table provides a brief description of each new business project.

Table JHZ-D-13
Discrete New Business Plant Additions ($ millions)

Project Name	Actual Additions 10/1/2019 - 6/30/2020	2021 HTY Actual Additions 7/1/2020 - 6/30/2021	Description
CO/Aurora/Aurora Highlands/N Lateral**	-	$2.8	Installed 8" HP steel main, 12" HP steel main, and two regulator stations to serve the new Highlands residential development.
CO/GATEWAY/Horizon **	-	$2.7	Installed 7,800’ of new 6" IP main to serve the new reg station that will feed the new Horizon residential development in Aurora.
CO/SWMR/4in IP Englewood WWTP	$1.8	-	Installed 2,437’ of 4" IP main to connect to the new interconnect receipt facility to provide

Project Name	Actual Additions 10/1/2019 - 6/30/2020	2021 HTY Actual Additions 7/1/2020 - 6/30/2021	Description
			renewable natural gas to our system.
CO/Strlng/Hipl/Hwy 71 & CR T /New Business	-	$1.7	Installed 15,840’ of 4" IP main to serve a new commercial customer in Brush, CO.
CO/BLDR/LONG/Long mont EL-25-81-96	-	$1.7	Installation of 6” and 2” distribution main in Longmont area.
CO-Transmission Reg and Meter	$0.4	$1.5	Various activities in support of Transmission Regulator and Meter Station activities
CO/SWMR/LE/LAKE/W ESTLINE VILLAGE/GD	-	$1.3	Installed 3,850’ of 8" PE main and 800’ of 4" PE main to support 44 new townhomes.
CO/Aurora/Painted Prairie	$1.1	-	Installation of 150’ Transmission Main, Two Regulator Stations for new Painted Prairie residential subdivision in Aurora.
CO/NEMR/DIA-Rock and Rail Reinforcement	$1.0	($0.5)	Installed 2,000’ of HP main, new regulator station, and a new customer meter set for this North Metro industrial customer.
CO/DMR/Auraria Campus Steam Conversion	$0.9	($0.0)	Installation of 4,300’ of 4" main in support of campus conversion from steam
CO/BLDR/LOUIS/EU-1 PL Reinforcement	$0.8	$0.1	Installation of new 6” main in Louisville area.
New Business - CIAC	($4.5)	($7.5)***	Contribution in aid of construction payments to the Company
New Business - Other	$4.2	$5.1	Various other New Business activities
Total New Business Discrete	**$5.7**	**$8.8**	

**Any differences in sums due to rounding*

*** Project has one page attachment providing more information in Attachment JHZ-9*

********The contributions in aid of construction (“CIAC”) amount reflects the fluctuation in timing of CIAC payments over the full 2021 calendar year.*

Q. PLEASE DESCRIBE THE DISCRETE NEW BUSINESS PROJECTS THAT ARE BEING ADDED FROM JULY 1, 2021 THROUGH DECEMBER 31, 2021 AND FOR THE 2022 CTY.

A. Table JHZ-D-14 below lists the key discrete New Business projects that will be in service between July 1, 2021 and December 31, 2021 and for the 2022 CTY. In addition, the Table provides a brief description of each of these New Business projects.

Table JHZ-D-14
Discrete New Business Plant Additions July 1, 2021 through December 31, 2022 ($ millions)

Project Name	Forecasted Additions 7/1/2021 - 12/31/2021	2022 CTY Forecasted Additions 1/1/2022 - 12/31/2022	Description
Canyons Development**	$4.0	-	Installation of 6,080' of 6" HP steel main and a new regulator station to serve the new Canyons mixed use development in Castle Pines.
CO/Lakewood/Rooney Valley - F994**	$2.6	-	Installation of 5,500' of 8" IP steel main and a new regulator station to serve three new Rooney Valley residential developments.
CO/Aurora/Aurora Highlands/N Lateral**	$0.9	-	Installation of 8" main and 12" main to support the new Highlands residential development.
CO-Transmission Reg and Meter	$0.2	$0.5	Various activities in support of Transmission Regulator and Meter Station activities
New Business – CIAC***	$2.2***	($3.1)	Contribution in aid of construction payments to the Company
New Business - Other	$5.1	$1.4	Various other New Business activities
Total New Business Discrete	**$15.0**	**($1.2)**	

**Any differences in sums due to rounding*
*** Project has one page attachment providing more information in Attachment JHZ-9*
**** The CIAC amount reflects the fluctuation in timing of CIAC payments over the full 2021 calendar year.*

I provide additional detail regarding key New Business capital plant additions in the next section of my Direct Testimony.

Q. CAN YOU PROVIDE MORE INFORMATION ABOUT THE COMPANY'S DISCRETE NEW BUSINESS CAPITAL PROJECTS?

A. Yes. Attachment JHZ-9 contains project-specific information for each of the new projects listed in Tables JHZ-D-13 and JHZ-D-14 that are $2 million or higher (also denoted with a **). In addition, in the next segments of my Direct Testimony, I discuss two of the largest New Business discrete projects in these periods, which include the Canyons Development and Aurora Highlands, as well as the "Other" New Business category.

Q. HOW DOES THE NEW BUSINESS BUDGET FOR THE 2022 CTY COMPARE TO ACTUAL CAPITAL ADDITIONS IN RECENT YEARS?

A. Table JHZ-D-14 above illustrates that the Company only budgets for known discrete new business projects if they are identified ahead of budget creation; emerging discrete new business projects that come up after budget creation utilize funding from the routines.

A. Key New Business Discrete Projects Since the 2019 HTY

1. Canyons Development

Q. WHAT IS THE CANYONS DEVELOPMENT PROJECT?

A. The Canyons Development project is a new development east of Castle Pines, Colorado and will contain approximately 1,500 residential units. The current project is designed to bring sufficient gas into the subdivision to provide service to these customers, including the initial 325 apartment units expected to be connected to the system in the second quarter of 2022.

Q. PLEASE PROVIDE AN OVERVIEW OF THE WORK INVOLVED IN COMPLETING THE CANYONS DEVELOPMENT PROJECT.

A. The scope of the Canyons Development project was to install approximately 1.1 miles of 6-inch high pressure 285 psig pipeline and install a new high pressure-to-pounds medium regulator station F-976 to serve the new development. Project construction has been completed.

Q. WHAT ALTERNATIVES TO THE CANYONS DEVELOPMENT PROJECT DID THE COMPANY CONSIDER?

A. Alternatives to the project were evaluated in a third-party study that looked at multiple pipeline routes, each of which would be customer-funded. The study evaluated engineering, route surveys, and geotechnical aspects for numerous pipeline routes before selecting the final route.

2. Aurora Highlands

Q. WHAT IS THE AURORA HIGHLANDS PROJECT?

A. The Aurora Highlands project is located in the Aurora, Colorado area as part of the larger Aerotropolis Regional Transportation Authority development. The Aurora Highlands development is to be built over phases with a potential build-out of 23,000 residences.

Q. PLEASE PROVIDE AN OVERVIEW OF THE WORK INVOLVED IN COMPLETING THE AURORA HIGHLANDS PROJECT.

A. The scope of the Aurora Highlands project was to install two new regulator stations (F-982 and F-983) and installation of an 8-inch 285 psig pipeline. This scope will cover the first feed into the development on the north side. A future project will provide a similar feed into the southern portion development once that development begins.

Q. WHAT ALTERNATIVES TO THE AURORA HIGHLANDS PROJECT DID THE COMPANY CONSIDER?

A. There were limited alternatives to this project since the location of service was dictated by the developer and one option explored was to install a singular high pressure to pounds medium regulator station. This option was rejected due to potential reliability impacts around a single delivery point for the entire development. The single station approach would have resulted in higher distribution main costs as they would require a larger diameter distribution main to carry the gas throughout the development. The project scope chosen builds the first feed into the development, with a second feed added once development starts in the southern portion.

Q. HAS THE AURORA HIGHLANDS PROJECT BEEN COMPLETED?

A. Yes, the majority of the Aurora Highlands Subdivision project was in-serviced in July 2020, with additional infrastructure in-serviced in October 2021.

3. New Business – Other

Q. WHAT OTHER NEW BUSINESS ADDITIONS HAS THE COMPANY MADE FROM OCTOBER 1, 2019 THROUGH THE 2022 CTY?

A. In addition to the discrete new business projects mentioned previously, the Company performs other projects to serve Colorado customer growth. Attachment JHZ-10 to my Direct Testimony includes the project name, capital additions, and description of each of the “New Business – Other” capital additions from October

1, 2019 through June 30, 2021, many of which are under $50,000. Furthermore, the Company is forecasting $5.1 million of plant additions during the last half of 2021 and $1.4 million during the 2022 CTY. Attachment JHZ-10 to my Direct Testimony provides the project name, capital additions, and description of the "New Business – Other" for this $6.5 million in plant additions.

B. New Business Routines

Q. WHAT ARE NEW BUSINESS ROUTINES?

A. These routines cover the purchase of new meter and service regulators and the installation of new distribution mains and services for projects typically less than $300,000, in order to serve new customers.

Q. CAN YOU PROVIDE MORE DETAIL REGARDING THE KINDS OF PROJECTS COVERED BY NEW BUSINESS ROUTINES FROM OCTOBER 1, 2019 THROUGH JUNE 30, 2021?

A. New business routines involved the purchase of new meters and service regulators and the installation of new distribution mains and services. The drivers for these types of projects are outlined previously in this section. Table JHZ-D-15 below shows the plant additions in support of new customer additions along with the number of feet of new main additions to support customer growth.

Table JHZ-D-15
New Business Routines Plant Additions and Footages
October 1, 2019 to June 30, 2021 ($ millions)

Routine Description	Actual Additions 10/1/2019 - 6/30/2020	2021 HTY Actual Additions 7/1/2020 - 6/30/2021	Total
New Meter and Regulator Purchases	$15.7	$33.9	**$49.6**
New Service Additions ($M)	$18.6	$26.2	**$44.8**
New Main Additions ($M)	$19.6	$22.5	**$42.0**
New Main Additions (feet)	534,966	492,249	**1,027,215**

** Any differences in sums due to rounding*

Q. WHAT PROJECTS ARE COVERED BY NEW BUSINESS ROUTINES FROM JULY 1, 2021 THROUGH DECEMBER 31, 2021 AND FOR THE 2022 CTY.

A. Table JHZ-D-16 below contains the forecasted plant additions in support of New Business routines for the project types described above from July 1, 2021 through December 31, 2021 and for the 2022 CTY.

Table JHZ-D-16
Forecasted New Business Routines Plant Additions
July 1, 2021 to December 31, 2022 ($ millions)

Routine Description	Forecasted Additions 7/1/2021 - 12/31/2021	2022 CTY Forecasted Additions 1/1/2022 - 12/31/2022	Total
New Meter and Regulator Purchases	$9.3	$42.9	**$52.2**
New Service Additions ($M)	$10.8	$30.3	**$41.1**
New Main Additions ($M)	$16.7	$32.0	**$48.7**

Q. WHAT METHODOLOGY DID PUBLIC SERVICE USE TO FORECAST NEW GAS BUSINESS ADDITIONS FOR JULY 1, 2021 THROUGH THE 2022 CTY?

A. First, the forecast for the number of customers that are expected to request new gas service for the following calendar year is obtained from the Company's Sales, Energy, and Demand Forecasting department. Second, the budget for new business routines is then developed using a cost-per-customer from historical actuals in addition to corporate escalation factors including, but not limited to labor, non-labor, contractor, materials, equipment and fleet escalation rates, and bargaining labor increases.

Q. WHY IS THE NEW BUSINESS ROUTINE BUDGET FOR JULY 1, 2021 THROUGH THE 2022 CTY REASONABLE?

A. As with the Company's other routine budgets, the work covered by these budgets is necessary to serve customers and the budgeted amounts for July 1, 2021 through the 2022 CTY are reasonable. As previously discussed, the Company's budget for new business routines is based on the customer additions forecast and assumptions and the cost-per-customer from historical actuals. The historical customer addition actuals and forecast are then used to develop the new business routine budgets.

VI. MANDATED RELOCATIONS

Q. WHAT ARE MANDATORY RELOCATION PROJECTS?

A. Mandated Relocations are capital projects that require Public Service to move existing infrastructure in order to meet federal, state, or local requirements. This includes relocating facilities that are in direct conflict with street expansions within public rights-of-way and safety-related work required by a governing authority. An example is the CO/SOUTH/Silverthorne/Coyne Valley relocation, which was required by the City of Breckenridge in 2020 due to road and bridge improvements and included the relocation of approximately 715 feet of 6-inch transmission main, 571 feet of 3-inch transmission main and one valve set. The total cost of this project was $1.6 million.

Q. WHAT ARE THE RESULTING PLANT ADDITIONS TO SUPPORT MANDATORY RELOCATIONS FROM OCTOBER 1, 2019 THROUGH THE 2022 CTY?

A. Table JHZ-D-17 below identifies the mandatory relocations plant additions between discrete and routine projects.

Table JHZ-D-17
Mandatory Relocation Plant Additions
Routines vs. Discrete Projects ($ millions)

Relocations	Actual Additions 10/1/2019 - 6/30/2020	2021 HTY Actual Additions 7/1/2020 - 6/30/2021	Forecasted Additions 7/1/2021 - 12/31/2021	2022 CTY Forecasted Additions 1/1/2022 - 12/31/2022
Routines	$6.5	$6.4	$6.4	$16.0
Discrete	$6.9	$17.8	$11.7	$6.3
Total	**$13.4**	**$24.1**	**$18.1**	**$22.3**

** Any differences in sums due to rounding*

A. Discrete Mandated Relocations

Q. WHAT ARE THE PLANT ADDITIONS FOR DISCRETE MANDATORY RELOCATION PROJECTS FROM OCTOBER 1, 2019 TO JUNE 30, 2021?

A. The Company implemented $24.6 million of discrete mandatory relocation plant additions from the 2019 HTY to June 30, 2021. Several larger, individual projects were included in that total, as shown in Table JHZ-D-18. The Table also provides a description of each project.

Table JHZ-D-18
Mandatory Relocations Plant Additions
October 1, 2019 through June 30, 2021 ($ millions)

Project Name	Actual Additions 10/1/2019 - 6/30/2020	2021 HTY Actual Additions 7/1/2020 - 6/30/2021	Description
PSCo Central 70 Project	($0.6)	$8.0	Ongoing main, service, and regulator station relocations in support of 10 miles of Interstate 70 reconstruction in central Denver area.
CO/SWMR/US 85 CDOT Gas Main Relocation	-	$3.4	Relocated 4700' of 3" MW IP gas main, 500' of 2" IP gas main, and 2500' of 3" MW PM gas main to avoid conflict with CDOT construction to widen US 85 near Louviers.
Two Basins-G	$2.0	$0.5	Ongoing main relocations in support of Two Basins project by the City of Denver in conjunction with the Central 70 project.
CO/CAMP/Picadilly & 64th Relocation	$1.9	-	Relocation of 6,100' of 8" high pressure main

Project Name	Actual Additions 10/1/2019 - 6/30/2020	2021 HTY Actual Additions 7/1/2020 - 6/30/2021	Description
			due to road expansion efforts in Aurora.
CO/SOUTH/Silverthorne/Coyne Valley	-	$1.6	Relocation of 715' of 6" NPS HP Main pipeline and 571' of new 3" steel gas distribution pipeline due to construction of new bridge in Breckenridge.
CO/FR/Miner St Idaho Spring Relocation	$1.3	-	Relocation of 2,700' of 1 1/4" distribution main with 2" main in Idaho Springs due to reconstruction of road
CO/East/Aurora/Majestic Commerce Relocation	$1.3	-	Relocation of 1,700' of 8" high pressure main due to construction of a new bridge and road.
CO/Alamosa/1st St Relocation/Phase	-	$1.2	Relocation of 1,160' of 4" IP main and installed 1,635' of 2" PE PL main due to city storm drain construction.
CO/Platteville/WCR 34-WCR 13	($1.4)	-	Relocation 1,416’ of 12" HP gas main (paid by Weld County), one Take-Off Valve Set, and lower 600’ of 4" & 2" HP gas main due to redesign of intersection.
Relocation - Other	$2.4	$3.0	Various mandated relocation projects.
Total Relocation Discrete	**$6.9**	**$17.8**	

** Any differences in sums due to rounding*

Q. PLEASE DESCRIBE THE DISCRETE MANDATORY RELOCATION PROJECTS THAT ARE BEING ADDED FROM JULY 1, 2021 THROUGH DECEMBER 31, 2021 AND FOR THE 2022 CTY.

A. From July 1, 2021 through December 31, 2021 and for the 2022 CTY, the Company is forecasting $18.0 million of discrete mandatory relocations, including several large projects shown in Table JHZ-D-19 below. The Table also provides a brief description of each project.

Table JHZ-D-19
Forecasted Mandatory Relocation Plant Additions July 1, 2021 to December 31, 2022 ($ millions)

Project Name	Forecasted Additions 7/1/2021 - 12/31/2021	2022 CTY Forecasted Additions 1/1/2022 - 12/31/2022	Description
CO/Grand Junction/US6 Clifton Relocation	-	$3.9	Relocate approximately 8,000' of the existing 8" HP Palisade Lateral main due to CDOT roadwork.
CO/NMR/MAN/WHE/ WADSWORTH & 35TH TO	$2.5	-	Relocate approximately 200' of 8" PE, 200' of 6" ARO, 2,700' of 6" PE, 5,000' of 4" PE, and 4,300' of 2" PE pipe due to new water and sewer lines.
CO/SWMO/Santa Fe US 85 @C470 Relocation	$1.9	-	Relocate 6,500' of 6" high pressure main, 1,200' of 3" high pressure main, and 200' of 24" high pressure main due CDOT widening of US Highway 85, and completion efforts related to relocation of high pressure main.
PSCo Central 70 Project	$0.1	$1.5	Ongoing main, service, and regulator station relocations in support of 10 miles of Interstate 70 reconstruction in central Denver area.

Project Name	Forecasted Additions 7/1/2021 - 12/31/2021	2022 CTY Forecasted Additions 1/1/2022 - 12/31/2022	Description
CO/DMR/E 21st Ave & Marion St/Gas Relocation	$1.3	-	Relocate approximately 140' of 12" steel main, 450' of 2" PE, 600' of 4" PE and 27 services due to new storm sewer construction.
CO/HPGE_SH52 WCR37 Relo Hudson-Keenesburg Lateral	$1.4	-	Relocate/Lower approximately 2,000' of HP main due to CDOT roadwork near Ft. Lupton.
National Western Center Redevelopment	$0.3	$0.9	Main and Service relocation, and two new regulator stations in support of the overall redevelopment.
Relocation - Other	$4.2	$0.1	Various mandated relocation projects.
Total Relocation Discrete	**$11.7**	**$6.3**	

** Any differences in sums due to rounding*

Q. DOES THE COMPANY REQUEST PAYMENT OR REIMBURSEMENT FOR MANDATORY RELOCATIONS FROM PARTIES WHO MAKE THE REQUEST?

A. Yes, whenever we can. For example, the Company seeks reimbursements from entities for relocations where the Company holds the appropriate land rights (fee or easement) for assets. A recent of example of this is the CO/Platteville/WCR 34 – WCR 13 relocation, which was required by Weld County in 2019 due to road and associated drainage culvert reconstruction and included the relocation of approximately 1,416 feet of 12-inch transmission main, valve set relocation, and lowering 600 feet of 4-inch and 2-inch transmission main. The Company held the land rights to the location of the existing 12-inch transmission main and valve set, so Weld County reimbursed the Company $1.0 million to relocate these assets. The 4-inch and 2-inch laterals were located within road right-of-way and therefore the Company paid for the remainder of the total project cost of $2.2 million.

Q. CAN YOU FURTHER BREAK DOWN THE MANDATED RELOCATION – OTHER ADDITIONS THE COMPANY MADE FROM OCTOBER 1, 2019 THROUGH THE 2022 CTY?

A. Yes. In addition to the discrete mandated relocation projects mentioned previously the Company also performs other projects to relocate facilities that are in direct conflict with street expansions within public right-of-ways and safety-related work required by a government authority. Attachment JHZ-11 to my Direct Testimony includes the project name, capital additions, and description of each of the "Relocation – Other" capital additions from October 1, 2019 through June 30, 2021, many of which are under $50,000. Furthermore, the Company is forecasting $4.2 million of plant additions during the last half of 2021 and $0.1 million during the 2022 CTY. Attachment JHZ-11 to my Direct Testimony provides the project name, capital additions, and description of the "Relocation – Other" for $4.3 million in plant additions during this time period.

B. Routine Relocations

Q. WHAT ARE ROUTINE RELOCATIONS?

A. Routine relocation projects are mandated to meet federal, state, or local requirements and are typically less than $300,000. This includes relocating and renewal of pipelines that are in direct conflict with street expansions within public rights-of-way and safety-related work required by a governing authority.

Q. HOW DOES THE COMPANY BUDGET FOR ROUTINE RELOCATIONS?

A. Because the Company generally does not receive information about small relocations ahead of any given calendar year, the 2022 CTY budget for main relocation routines is based on the average of 2019 and 2020 actuals escalated by the corporate inflation rate (approximately three percent). The budget for main relocation routines is based on the averages of historical values escalated by the corporate inflation rate. The escalation factors include but are not limited to labor, non-labor, contractor, materials, equipment and fleet inflation rates, and bargaining labor increases. The Company only budgets for known discrete relocation projects if they are identified ahead of budget creation; emerging discrete relocation projects that come up after budget creation utilize funding from the relocation routines.

Q. CAN YOU PROVIDE MORE INFORMATION REGARDING THE KINDS OF PROJECTS COVERED BY MANDATORY RELOCATION ROUTINES FROM THE 2019 HTY THROUGH THE 2022 CTY?

A. Yes. Tables JHZ-D-20 and JHZ-D-21 below show the plant additions for routine mandatory relocations in support of the project types described above.

Table JHZ-D-20
Routine Mandatory Relocations Plant Additions and Footage
October 1, 2019 to June 30, 2021 ($ millions)

Routine Description	Actual Additions 10/1/2019 - 6/30/2020	2021 HTY Actual Additions 7/1/2020 - 6/30/2021	Total
Main Relocation Additions ($M)	$6.5	$6.4	**$12.9**
Main Relocation Additions (feet)	30,328	35,101	**65,429**

Table JHZ-D-21
Mandatory Relocations Routine Plant Additions
July 1, 2021 to December 31, 2022 ($ millions)

Routine Description	Forecasted Additions 7/1/2021 - 12/31/2021	2022 CTY Forecasted Additions 1/1/2022 - 12/31/2022	Total
Main Relocation Additions ($M)	$6.4	$16.0	**$22.3**

** Any differences in sums due to rounding*

Q. WHY IS THE BUDGET FOR THE TEST YEAR REASONABLE?

A. As we have previously discussed, our budgets for mandated relocation routines are based on historical data. From July 1, 2021 through December 31, 2021, the Company has budgeted $6.4 million in plant additions or an average of $1.1 million per month. For the 2022 CTY, the Company has budgeted $16.0 million in plant additions or an average of $1.3 million per month for projects that require Public Service to move existing infrastructure in order to meet federal, state, or local requirements. The Company has forecasted plant additions for the mandated routines in the 2022 CTY based on the average of historical actuals from 2019 and 2020 escalated by the corporate inflation rate (approximately three percent).

Actual mandated relocation plant additions in calendar year 2019 were $13.1 million or an average of $1.1 million per month, which further supports the reasonableness of the forecasted 2022 CTY additions.

VII. GAS OPERATIONS TARIFF CHANGES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I first provide an overview of Public Service's gas transportation services. I then summarize the tariff changes being proposed by the Company, specifically discussing the operational tariff matters that I support. Company witness Ms. Susan L. Bailey sponsors the remaining operational tariff changes in her Direct Testimony. All of the Company's proposed tariff changes, both clean and redlined, are attached to the Direct Testimony of Company witness Ms. Marci A. McKoane as Attachments MAM-3 and MAM-4.

A. Public Service's Gas Transportation Services

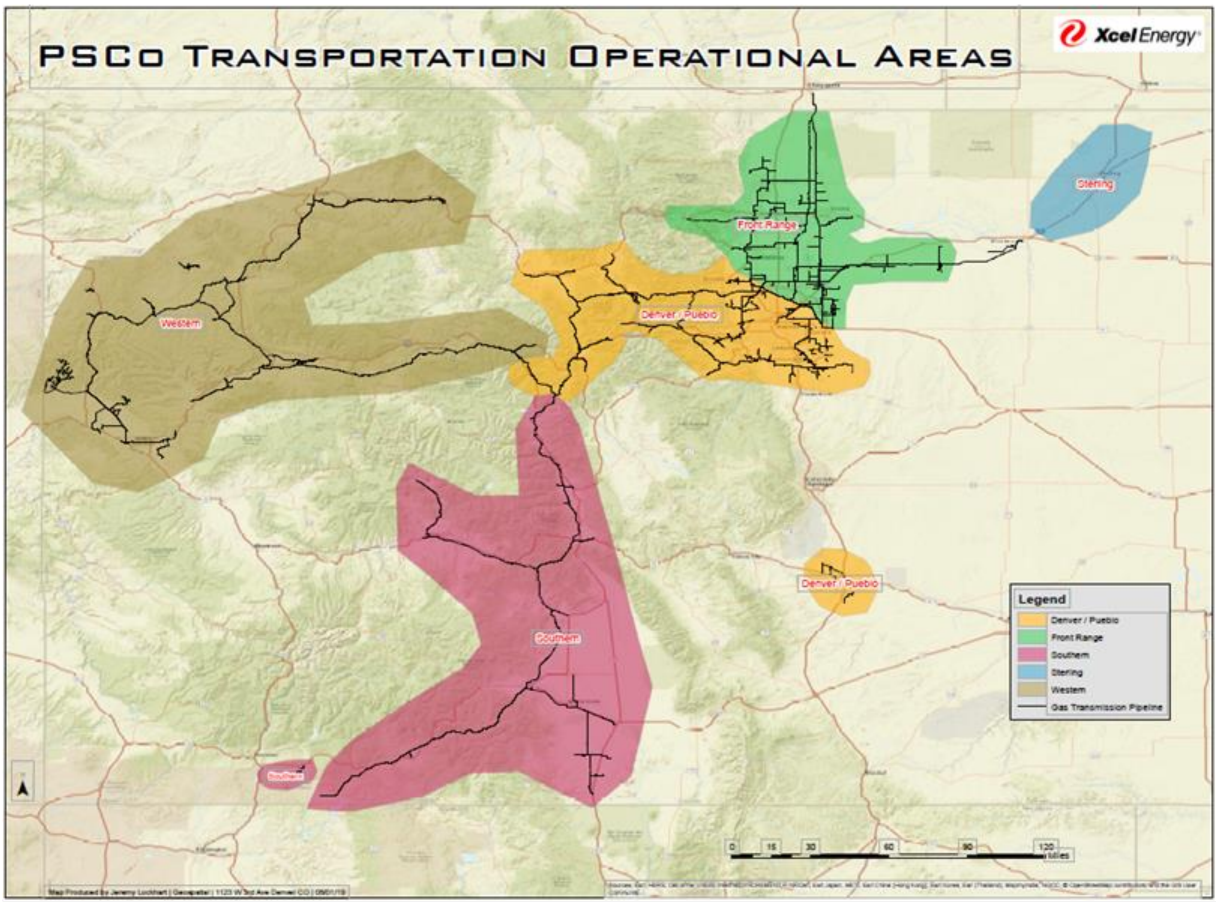
Q. PLEASE PROVIDE AN OVERVIEW OF PUBLIC SERVICE'S CURRENT GAS TRANSPORTATION SERVICES.

A. Public Service has been offering gas transportation service since the mid-1990s on both a firm and interruptible basis. The Company originally proposed gas transportation tariffs for Commission approval after several large customers approached us requesting the ability to purchase gas from a third-party. Gas transportation service allows Public Service's customers to purchase their gas supply directly from a producer or marketer and transport that gas from the point of acquisition, also known as a receipt point, to the customer's premise, known as the delivery point. Public Service charges the Shipper a transportation charge for that service.

Q. PLEASE DESCRIBE THE COMPANY'S NATURAL GAS TRANSPORTATION SYSTEM.

A. Public Service's natural gas transportation system is divided into several operational areas, not all of which are fully interconnected. Figure JHZ-D-2 below is a map of the Company's Operational Areas.

Figure JHZ-D-2:
Public Service Operational Area Map



It is important to note that even where Operational Areas are connected to each other, the gas may not flow between certain receipt and delivery points on a peak day due to capacity constraints on the system. Additionally, gas within an Operational Area may not flow between certain receipt and delivery points. To determine and manage capacity on the Company's system, Public Service must have the ability to manage where on the system Shippers may receive gas from the system or deliver gas into the system.

Q. WHAT IS A SHIPPER?

A. A Shipper is a party who takes Gas Transportation Service on Public Service's natural gas Transportation System, on either a firm or interruptible basis. The Shipper is the primary point of contact with Public Service in relation to coordinating transportation service, nominating gas, ensuring an adequate communication (phone) line to the Company's meter to allow for daily measurement readings, monitoring usage, and paying bills. A Shipper may be both the end user of these services (known as the "Receiving Party") and the party interfacing with Public Service, or the Shipper may be an agent (such as a marketer) that does not take service directly but rather manages transportation service on behalf of the end use customer.

Q. PLEASE SUMMARIZE THE MAJOR GAS TRANSPORTATION SERVICE REQUIREMENTS AND SHIPPER RELATIONSHIPS.

A. A customer that elects to purchase its gas on the open market may take service from Public Service solely or primarily as a transportation customer. Transportation service can be elected at any time; however, once an election is made to go on a transportation service, the customer must remain on that service for a specified period of time, typically a minimum of 12 months. A customer (sometimes called an end-use customer or "Receiving Party") can act on its own behalf to become a Shipper, or can contract with an Agent who will be the Shipper that can act on behalf of the Receiving Party, as authorized. An Agent can also be authorized to act on behalf of multiple Receiving Parties, and can manage its aggregated portfolio under one contract, by Public Service operational area as set forth in Figure JHZ-D-2 above.

Q. WHAT ARE THE MAJOR TYPES OF GAS TRANSPORTATION SERVICE AVAILABLE UNDER THE COMPANY'S CURRENT TARIFFED RATE SCHEDULES?

A. Public Service currently offers the following three primary transportation rate schedules under its Gas Tariff, Firm Gas Transportation Service Large – Schedule TFL ("TFL"), Firm Gas Transportation Service Small – Schedule TFS ("TFS"), and Interruptible Gas Transportation Service – Schedule TI ("TI"). Ms. Bailey provides more information on these rate schedules in her Direct Testimony.

Q. HOW MUCH OF THE THROUGHPUT ON THE COMPANY'S SYSTEM IS ATTRIBUTABLE TO TRANSPORTATION CUSTOMERS?

A. Public Service's gas transportation service represents about 55 percent of the gas throughput on the Company's system. The remaining throughput is sales gas; delivered to residential, commercial, and industrial customers. Under its gas transportation services, Public Service serves approximately 8,000 premises in the five operational areas contained in the map in Figure JHZ-D-2 above.

B. Proposed Gas Operations Tariff Changes

Q. PLEASE SUMMARIZE THE GAS OPERATIONS TARIFF CHANGES THE COMPANY IS PROPOSING IN THIS PROCEEDING.

A. As explained by Ms. Bailey, the Company's Gas Transportation Terms and Conditions and rate schedules were significantly updated as part of the Company's 2019 Phase II Proceeding No. 19AL-0309G ("2019 Gas Phase II"). Many of our proposed tariff revisions in this proceeding either further clarify the terms, or build upon these ongoing efforts to modernize the transportation portions of the Gas Tariff consistent with Public Service's operational requirements. These proposed revisions include, but are not limited to, clarifications or updates to the Gas Transportation Terms and Conditions, Schedule IG, and the TFL, TFS, and TI Gas rate schedules in the Gas Tariff regarding:

- Primary receipt points, including related provisions concerning unauthorized overrun penalties,
- Requirements for Firm Transportation Service and the On-Peak Demand Quantity Option;
- Minimum duration for Receiving Party commitments to the On-Peak Demand Quantity option;
- Sunsetting the Backup Sales Service option;
- Security for gas transportation service;
- Nomination of gas for imbalance resolution;
- Hourly receipt and delivery quantities; and
- Service agreement suspension, termination, and agency agreement revocation.

Related to these tariff revisions, in our gas transportation and interruptible sales rate schedules, we have also proposed to increase the unauthorized overrun penalty charge to ensure that gas transportation customers are adequately incentivized to comply with operational flow orders, curtailment orders, and orders to move to primary receipt points. We are also proposing tariff changes related to the Company's gas quality provision related to gas from hazardous waste landfills as contained in our Rules and Regulations applicable to all gas services.

As supported by Ms. Bailey, Public Service also proposes revisions to the Gas Tariff that relate to interruptible service for both transportation and sales customers to ensure such customers are adequately prepared and incentivized to comply with curtailment orders and other requirements for interruptible service. Several of these proposed tariff revisions were previewed in my Direct and Rebuttal Testimony in support of Public Service's application to recover Winter Storm Uri-related extraordinary fuel costs in Proceeding No. 21A-0192EG. To the extent the Commission's decisions through Proceeding No. 21A-0192EG address any of Public Service's proposed tariff changes over the course of this proceeding, we will update our requests accordingly.

The Company is also proposing a number of clarifying and housekeeping changes related to gas transportation and interruptible gas sales service, which are further explained and supported by Ms. Bailey.

While Ms. Bailey supports the majority of these proposed updates through her Direct Testimony, I support our proposed tariff revisions pertaining to primary Receipt Points, hourly receipt and delivery quantities, and gas quality.

1. Primary Receipt Points

Q. PLEASE GENERALLY DESCRIBE THE ROLE OF PRIMARY RECEIPT POINTS.

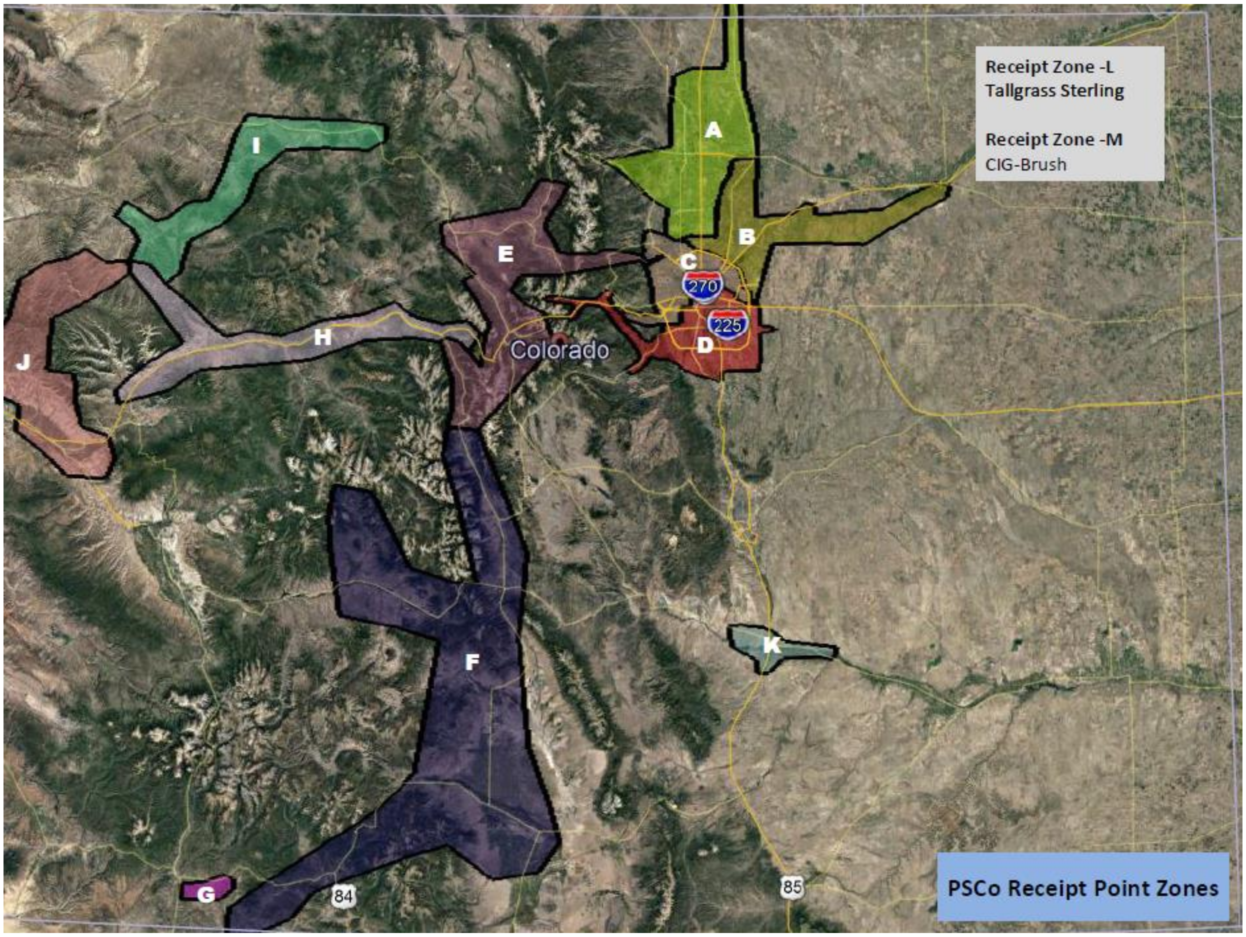
A. Primary Receipt Points are specified in firm gas transportation service agreements where Receiving Parties are entitled to source gas onto Public Service's system. While a Shipper can request to shift firm capacity from a Primary Receipt Point to another alternate Receipt Point (referred to in the Gas Tariff as a Secondary Receipt Point) on a temporary basis through the nomination process, Primary Receipt Points are where a Receiving Party is ultimately entitled to firm gas transportation service. Conversely, the Primary Receipt Point is the location at which the Company can rely on the Receiving Party to receive gas supply; therefore it is critical to capacity planning processes – particularly on days involving system constraints like a design day. As an example, if Shippers in the Denver metro or Front Range areas use out of path Receipt Points when the system is constrained, gas that is allocated for Public Service's sales customers may need to be used to serve these Shippers' customers. In this case, Public Service might lose adequate supply going to the mountain system, which would, after a period of time, result in inadequate pressures required to serve these mountain system customers. As another example, in areas of the system where Public Service customers are served by a single receipt point, a Shipper who selects an out-of-path Primary Receipt Point might use gas that would deprive firm sales customers from access to adequate gas supply on a Design Day.

Q. HOW ARE PRIMARY RECEIPT POINTS DETERMINED?

A. The Company's gas system is reticulated, meaning that it is constructed like a network where on any given day gas could physically flow from one receipt point, and on another day, it could physically flow from a different receipt point. However, not all receipt points on the Company's system can physically flow gas to a customer's premise. This means that the Primary Receipt Points currently on certain Shippers' agreements – if not "in-path" – may not enable gas to be physically provided to delivery premises. In such instances, gas would be transported through "displacement," which is the non-physical movement of gas volumes dependent on a substitution from one source of natural gas at one point to another source of natural gas at a different point. Under Commission Rule 4206(b), the utility is not required to perform exchanges or displacements over segments of its system that are not physically connected.

The map in Figure JHZ-D-3 below reflects the Company's Receipt Point Zones. Customers physically located within a zone must select a primary receipt point that is in that same zone to ensure gas will flow to that customer on a constrained day.

Figure JHZ-D-3:
Public Service Receipt Point Zone Map



In addition, the in-path receipt points available for each zone are reflected in Attachment JHZ-12 to my Direct Testimony.

Q. WHAT DOES THE COMPANY DO IF A SHIPPER SEEKS TO USE A PRIMARY RECEIPT POINT THAT IS NOT IN-PATH?

A. Public Service honors the Receipt Points specified in Shippers' firm transportation agreements. However, when a Shipper who does not have a Primary Receipt Point that is "in-path" (i.e., a Receipt Point that does not utilize displacement) seeks to amend the agreement, Public Service requires the Shipper to identify in-path Primary Receipt Points before it will agree to the contract amendment.

Q. WHY DOES THE COMPANY REQUIRE IN-PATH PRIMARY RECEIPT POINTS?

A. The purpose of requiring in-path Primary Receipt Points is to ensure safe and reliable service to customers on days when the system is constrained. Under the current gas tariff, the Company considers multiple factors related to whether it has sufficient capacity available for transportation services, which includes consideration of all conventional methods of delivering gas discussed in Commission Rule 4206(b). Requiring in-path Primary Receipt Points is necessary for the Company to plan for and ensure adequate capacity throughout the system, particularly on constrained days like a design day. Public Service, however, continues to accept the use of displacement through Secondary Receipt Points when the system is not constrained.

Q. HOW DO IN-PATH PRIMARY RECEIPT POINTS BENEFIT CUSTOMERS?

A. If the Company continues to allow Shippers to use secondary receipt points through displacement on a design day, then the Company may have to build additional infrastructure in order to ensure there is adequate capacity to provide reliable service to all customers. That capital investment can be avoided or reduced if Shippers simply utilize an in-path primary receipt point on constrained days.

Q. PLEASE DESCRIBE PUBLIC SERVICE'S PROPOSED TARIFF REVISIONS CONCERNING PRIMARY RECEIPT POINTS.

A. Instead of needing to update firm transportation agreements on a one-off basis with individual Shippers who seek to amend their agreements, Public Service is proposing to implement several tariff revisions through this proceeding that will clarify the requirement that all agreements for firm transportation service, as well as commitments to provide firm capacity through the On-Peak Demand Quantity Option for interruptible transportation customers, select Primary Receipt Points that are in-path. The proposed tariff language clarifies that all Shippers must state in-path Primary Receipt Points in gas transportation service agreements.

Q. HOW WOULD PUBLIC SERVICE DETERMINE WHEN IT IS OPERATIONALLY REQUIRED FOR SHIPPERS TO USE IN-PATH PRIMARY RECEIPT POINTS?

A. The Company utilizes hydraulic modeling to determine whether points are in-path on a constrained day. Public Service plans to continue allowing Shippers to use Secondary Receipt Points that rely on displacement to deliver gas when there is adequate pipeline capacity to provide firm service for all transport and sales customers entitled to it. However, on constrained days when there is not adequate pipeline capacity, we will require Shippers to use in-path Primary Receipt Points that allow for the physical delivery of gas to receiving parties.

Q. WHAT ARE THE POTENTIAL CONSEQUENCES IF A SHIPPER DOES NOT COMPLY WITH AN ORDER TO USE AN IN-PATH PRIMARY RECEIPT POINT?

A. Due to the critical nature of this requirement to ensure safe and reliable service for all customers, Public Service proposes provisions to emphasize its right to ensure that Shippers comply with orders to in-path Primary Receipt Points, including, but not limited to, the application of unauthorized overrun penalties for continued usage at secondary Receipt Points once Public Service has ordered Shippers to return to in-path Primary Receipt Points. Public Service also emphasizes through the proposed tariff changes its right to terminate or suspend a Shipper's service agreement for failure to comply with such an order. The proposed tariff revisions related to this topic are reflected in Attachment SLB-1 to Ms. Bailey's Direct Testimony, at Tariff Sheet Nos. T49 and T50.

2. Hourly Receipt and Delivery Quantities

Q. PLEASE DESCRIBE PUBLIC SERVICE'S REQUIREMENTS FOR HOURLY RECEIPT AND DELIVERY QUANTITIES.

A. Currently, Public Service's Gas Transportation Terms and Conditions require that Shippers must cause gas to be tendered at Receipt Points at a constant hourly flow rate throughout the day equal to a flow rate of 1/24 of the daily scheduled quantity.[12] The Gas Transportation Terms and Conditions further provide that the Company can restrict a Shipper's receipt quantities or restrict or adjust delivery quantities to address negative operational consequences caused by an inconsistent or variable flow rate.

Q. WHY IS THIS REQUIREMENT IMPORTANT?

A. This requirement is important to ensure Public Service maintains adequate pipeline capacity to provide safe and reliable service to all gas customers and

[12] See Gas Tariff Sheet No. T27.

ensure that gas transportation customers cover their fair share of the costs necessary to serve them and avoid cross-subsidization by other customers. When a gas transportation customer causes gas to be tendered at a rate significantly exceeding 1/24 of the customer's daily scheduled quantity, the customer is using more pipeline capacity than we have allocated to that customer and charged that customer for in planning investments for supporting capacity.

Q. WHAT TARIFF UPDATES DOES PUBLIC SERVICE PROPOSE CONCERNING THIS REQUIREMENT?

A. The proposed tariff revisions clarify that the 1/24 requirement applies to Delivery Points, and allows the Company to evaluate Shippers' maximum daily quantity ("MDQ") and maximum hourly usage at any time if they are taking service under Schedule TFL. If a Shipper's maximum hourly flow rate increases above the 1/24 requirement, the Company will determine whether capacity is available to serve the Shipper at the larger maximum hourly flow rate and associated MDQ, and if not, it may be necessary for the Shipper to fund system reinforcements to provide firm service consistent with the Company's Distribution Extension Policy. The Company may also implement flow control equipment to address the capacity constraint issues at the Shippers expense. In this situation, the Company retains the right to exercise other available remedies. If system reinforcements are required, during the construction period the Company will also not be required to provide firm service to Shippers or Receiving Parties, and Shippers may elect to transfer to Interruptible Transportation Service or place a portion of their load on an On-Peak Demand Quantity Option, if available.

Q. WHY IS THIS REQUIREMENT IMPORTANT?

A. This requirement is important to ensure Public Service's hydraulic modeling is reflective of a customer's expected hourly usage. Without this provision, the Company must assume the customer's daily to hourly conversion. For example, if a customer has an MDQ of 2,400 Dth, at 1/24 their usage would be 100 Dth per hour, which may not be an accurate reflection of the customer's actual hourly usage. The proposed tariff modifications will allow the Company to more accurately model a customer's maximum hourly usage, and charge the appropriate demand rate to the customer.

3. Gas Quality

Q. ARE THERE ANY CLARIFICATIONS THAT PUBLIC SERVICE PROPOSES TO THE RULES AND REGULATIONS APPLICABLE TO ALL SERVICES REGARDING GAS QUALITY?

A. Yes, the Company proposes certain clarifications to the Gas Quality Specifications regarding gas from hazardous waste landfills as found on Tariff Sheet No. R24D (subpart m) of its Gas Tariff. For purposes of this subpart m, we clarify that "hazardous waste" is as defined by 40 C.F.R. § 261.3 (6 CCR 1007-3 § 261.3) and "landfill" is as defined by 40 C.F.R. § 260.10 (6 CCR 1007-3 § 260.10). The Company makes clear that it will accept biomethane from landfills that are not or have not previously been designated a hazardous waste landfill, so long as the biomethane gas meets the Gas Quality Specifications found throughout the Company's Gas Tariff.

Q. WHY DOES PUBLIC SERVICE BELIEVE THESE TARIFF UPDATES ARE APPROPRIATE?

A. The Company anticipates that in the future as part of any potential Renewable Natural Gas project that we may be asked to accept biomethane gas from a landfill. If that occurs the Company will accept that gas as long as it meets the Gas Quality Specifications in our Gas Tariff.

VIII. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING THOUGHTS FOR THE COMMISSION'S CONSIDERATION?

A. In this proceeding, the Company requests recovery of capital investments that are necessary and prudent to serve Public Service customers. These investments are carefully planned and implemented to provide safe, reliable, cost-effective service, in compliance with applicable rules and regulations, customer and system needs, and local government mandates. Additionally, the Company's proposed tariff changes will help confirm, clarify, or enhance the efficient operation of the natural gas system for the benefit of all customers.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Joni H. Zich

I received a Bachelor of Business Administration degree in Management Information Systems from the University of Wisconsin – Eau Claire in 1987. I received a Master of Business Administration from the University of Wisconsin – Eau Claire in 2000. I was hired by Northern States Power Company – Wisconsin ("NSPW") as an Information Specialist in the Marketing Department in 1988, progressing to an Analyst during my tenure in the Department. My experience in Marketing included the development of demand side management programs.

In 1994, I transferred to the Gas Supply and Planning department, where I was responsible for scheduling gas on several interstate pipelines to ensure system load requirements were balanced. After fifteen months, I was promoted to a trading position where I was responsible for the purchase and sale of natural gas supply for NSPW including the acquisition of physical supply agreements and the use of financial derivatives. I later managed the gas purchasing and sales activities, transportation scheduling, accounting operations, and NSPW's non-traditional wholesale gas sales programs.

In 1999, I transferred to Gas Resource Planning. In this role I was responsible for the development and implementation of dynamic strategic system planning for NSPW, Northern States Power – Minnesota (NSPM), and Northern States Power Company's gas fired generation for their respective upstream gas transportation and storage assets, ensuring reliable and cost effective delivery. As the Manager of Gas Resource Planning, I managed several regulatory proceedings regarding the cost recovery of upstream gas assets where I testified before several state regulatory commissions and at the Federal Energy Regulatory Commission (FERC).

In April 2012, I was promoted to Director of System Strategy and Business Operations for Xcel Energy Services Inc. ("XES") the "service company" subsidiary of Xcel Energy, Inc. ("Xcel Energy"), a registered holding company. In this capacity, I am responsible for the long term gas capacity planning for the Company's high-pressure and intermediate-pressure gas system, the overall financial governance of the gas operations including capital investments, management and administration of integrity management riders (including the PSIA), and the development of gas emission reduction strategies. In addition, I direct the Natural Gas Services team, which manages all aspects of Public Service's gas transportation services. In addition to these responsibilities, in January 2021, I also began directing the Company's gas governance organization which includes gas standards, compliance, contractor inspections, quality assurance, and the Pipeline Safety Management System (PSMS) when I was promoted to Senior Director, Strategy, Governance and Planning.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * *

IN THE MATTER OF ADVICE NO. 993-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO INCREASE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL GAS RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE FEBRUARY 24, 2022	) PROCEEDING NO. 22AL-_____G

AFFIDAVIT OF JONI H. ZICH
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, Joni H. Zich, being duly sworn, state that the Direct Testimony and attachments were prepared by me or under my supervision, control, and direction; that the Direct Testimony and attachments are true and correct to the best of my information, knowledge and belief; and that I would give the same testimony orally and would present the same attachments if asked under oath.

Dated at Hayward, Wisconsin, this 21 day of January, 2022.

Joni H. Zich

Joni H. ZIch
Senior Director, Strategy, Governance and Planning

Subscribed and sworn to before me this 21 day of January, 2022.

PETER ANDERSON NOTARY PUBLIC STATE OF WISCONSIN

Peter Anderson

Notary Public

My Commission expires 4/15/2024