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

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IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR COLORADO'S POWER PATHWAY 345 KV TRANSMISSION PROJECT AND ASSOCIATED FINDINGS REGARDING NOISE AND MAGNETIC FIELD REASONABLENESS	**) PROCEEDING NO. 21A-XXXXE**

DIRECT TESTIMONY AND ATTACHMENTS OF BRIAN J. RICHTER

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

March 2, 2021

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

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IN THE MATTER OF THE APPLICATION	**)**
OF PUBLIC SERVICE COMPANY OF	**)**
COLORADO FOR A CERTIFICATE OF	**)**
PUBLIC CONVENIENCE AND NECESSITY	**)**
FOR COLORADO'S POWER PATHWAY	**)**
345 KV TRANSMISSION PROJECT AND	**) PROCEEDING NO. 21A-XXXXE**
ASSOCIATED FINDINGS REGARDING	**)**
NOISE AND MAGNETIC FIELD	**)**
REASONABLENESS	**)**

DIRECT TESTIMONY AND ATTACHMENTS OF BRIAN J. RICHTER

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LIST OF ATTACHMENTS

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2021 ERP & CEP	Company's upcoming Electric Resource Plan and Clean Energy Plan filing
AACE 18R-97 Practice	AACE International Recommended Practice No. 18R-97 Cost Estimate Classification System
ALJ	Administrative Law Judge
ASTM E2516 Standard or ASTM E2516 Guidelines	Standard Classification for Cost Estimate Classification System
CAR	Cost Analysis Report
CEP	Clean Energy Plan
Commission	Colorado Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
EAC	Estimate at Completion
ERP	Electric Resource Plan
InEight Estimate	InEight Estimate construction estimating software, formerly called "Hard Dollar"
kV	Kilovolt
MW	Megawatts
Extension	May Valley-Longhorn Extension
Pathway Project or Project	Colorado's Power Pathway 345 kV Transmission Line Project
PMBOK	Project Management Book of Knowledge
PMI	Project Management Institute

Acronym/Defined Term	**Meaning**
Public Service or Company	Public Service Company of Colorado
ROW	Right of Way
Staff	Staff of the Colorado Public Utilities Commission
TAM	Transmission Asset Management
XES	Xcel Energy Services Inc.
Xcel Energy	Xcel Energy Inc.

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

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DIRECT TESTIMONY AND ATTACHMENTS OF BRIAN J. RICHTER

I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Brian J. Richter and my business address is 1800 Larimer Street, Suite 600, Denver, Colorado 80202.

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

A. I am employed by Xcel Energy Services Inc. ("XES") as Senior Manager, Transmission Project Management. 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. As the Senior Manager of Transmission Project Management, I am responsible for directing project/portfolio managers in the full scope of their responsibilities associated with large and complex substation and transmission line projects. A description of my qualifications, duties and responsibilities is set forth after the conclusion of my Direct Testimony in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to provide support for the Company's Verified Application for a Certificate of Public Convenience and Necessity ("CPCN") for Colorado's Power Pathway 345 kilovolt ("kV") Transmission Project (the "Pathway Project" or "Project") and present the Company's cost estimate of $1.695 billion associated with the Pathway Project. I provide an overview of the Company's project management experience and processes and explain how Public Service has the necessary expertise to manage and construct a project of this magnitude. I explain the proposed semi-annual reporting associated with the Project which will be provided to the Commission over the next several years. Last, I discuss the Company's planned construction sequencing of the Project and identify the anticipated in-service dates by Project segment.

Q. BEFORE DESCRIBING THE ORGANIZATION OF THE REST OF YOUR DIRECT TESTIMONY, PLEASE PROVIDE A BRIEF DESCRIPTION OF THE PATHWAY PROJECT.

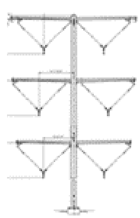
A. The Pathway Project involves constructing an approximately 560-mile, 345 kV double circuit network transmission system between seven substations. A vicinity map of the Pathway Project is provided as Attachment ARK-1 to the Direct Testimony of Company witness, Ms. Amanda R. King. The Project will connect the Front Range to areas of northeastern, eastern, and southeastern Colorado that are rich with potential for renewable energy resource development, but do not currently have a backbone[1] transmission system that can integrate new renewable energy resources needed to meet the State's clean energy goals. The northern terminus of the Pathway Project will be at the Company's existing Fort St. Vrain Substation (located at the Fort St. Vrain Generating Station) in Platteville in western Weld County. The Pathway Project then extends east to a new Canal Crossing Substation near the existing Pawnee Substation and Pawnee Generating Station; then extends east/southeast to a new Goose Creek Substation south of the City of Burlington; then extends south to a new May Valley Substation northeast of the City of Lamar; then extends west to the planned Tundra Substation near the Comanche Generating Station. The Project then extends north to the Company's existing Harvest Mile Substation, located adjacent to the City of Aurora

[1] A "backbone" system generally refers to bulk transmission lines networked together that can move large amounts of energy from a distant location to load areas. Backbone transmission systems support the reliability of the transmission system because of the networked nature of these systems. A grid supported by backbone transmission is better positioned to withstand outages without losing generation resource or load.

in Arapahoe County. The Project also involves expansion of the Fort St. Vrain, Pawnee, and Harvest Mile Substations; expansion of the planned but not yet in-service Tundra Substation; and construction of the new Canal Crossing, Goose Creek, and May Valley Substations. The three new substations will be 345 kV switching stations.[2] For purposes of its CPCN filing, the Company presents and describes the transmission line Project in five segments (Segments 1 through 5) between the existing or new substations. The Project Segments and components are summarized in Table BJR-D-1 below.

[2] A switching station is a type of substation that operates at a single voltage level (and, therefore, does not have transformers that change or "transform" voltage from one voltage level to another).

Table BJR-D-1: Project Segment Description Overview

Project Segment	**Project Segment Description** (approximate length in miles)
All Segments	**Colorado's Power Pathway 345 kV Transmission Project** Total 560 miles
	➢ The Project consists of five transmission line segments (Segments 1-5) as detailed below, with each segment bounded by substations. <u>Transmission Facilities:</u> ➢ The overall Project involves construction of approximately 560 miles of new 345 kV double circuit transmission line in new 150-foot wide right of way. ➢ Each segment of transmission line will be constructed using single pole, double circuit tangent structures (see typical structure diagram at left) and two-pole dead-end structures. The Project will utilize two-bundle 1272 kcmil ACSR Bittern conductor. <u>Substation Facilities:</u> ➢ The Project involves expansion of three existing substations (Fort St. Vrain, Pawnee, and Harvest Mile), expansion of a planned switching station (Tundra), and construction of three new substations which will be 345 kV switching stations (Canal Crossing [near and interconnected to existing Pawnee Substation], Goose Creek [near and interconnected to Cheyenne Ridge Wind Project, and May Valley [near but not interconnected to existing Lamar Substation]).
Fort St. Vrain Substation expansion	**Expand existing Fort St. Vrain Substation**: The existing 230 kV Fort St. Vrain Substation will be expanded, and a new 345 kV station arrangement will be established on land currently owned by Public Service.

Segment 1	**Fort St. Vrain Substation to Canal Crossing / Pawnee Substations** 75 miles
	Segment 1 involves constructing approximately 75 miles of new 345 kV double circuit transmission line from the existing Fort St. Vrain Substation to the new Canal Crossing and existing Pawnee Substations.
Canal Crossing Substation new construction	**Construct New Canal Crossing Substation:** A new 345 kV switching station will be constructed adjacent to the existing Pawnee Substation to accommodate new 345 kV line terminations and equipment on land currently owned by Public Service. The new Canal Crossing Substation is essentially an expansion of the Pawnee Substation and will interconnect to the Pawnee Substation *via* two short transmission ties.
Pawnee Substation expansion	**Expand existing Pawnee Substation:** The existing 345 kV Pawnee Substation will be expanded to accommodate new 345 kV line terminations and equipment on land currently owned by Public Service.
Segment 2	**Canal Crossing / Pawnee Substations to Goose Creek Substation** 160 miles
	Segment 2 involves constructing approximately 160 miles of new 345 kV double circuit transmission line from the new Canal Crossing and existing Pawnee Substations to a new 345 kV Goose Creek Substation located near the existing Cheyenne Ridge Wind Project.
Goose Creek Substation new construction	**Construct New Goose Creek Substation:** A new 345 kV switching station will be constructed on approximately 40 acres of land to be acquired by Public Service near the existing Cheyenne Ridge Wind Project. The new switching station will accommodate new 345 kV line terminations and equipment.

Segment 3	**Goose Creek Substation to May Valley Substation** 65 miles
	Segment 3 involves constructing approximately 65 miles of new 345 kV double circuit transmission line from the new Goose Creek Substation to a new 345 kV May Valley Substation.
May Valley Substation new construction	**Construct New May Valley Substation:** A new 345 kV switching station will be constructed on approximately 40 acres of land to be acquired by Public Service near the existing Lamar Substation. The new switching station will accommodate new 345 kV line terminations and equipment, but will not interconnect to the existing Lamar Substation.
Segment 4	**May Valley Substation to Tundra Substation** 140 miles
	Segment 4 involves constructing approximately 140 miles of new 345 kV double circuit transmission line from the new May Valley Substation to the planned Tundra Substation.
Tundra Substation expansion	**Tundra Substation:** The Tundra Substation is a 345 kV switching station planned to interconnect a solar with storage project approved as part of the Company's approved Colorado Energy Plan Portfolio that will be in service by the end of 2022. This Project will expand the planned Tundra Substation to accommodate new 345 kV line terminations and equipment. No new land acquisition is required for the expansion.
Segment 5	**Tundra Substation to Harvest Mile Substation** 120 miles
	Segment 5 involves constructing approximately 120 miles of new 345 kV double circuit transmission line from the Tundra Substation to the existing Harvest Mile Substation.
Harvest Mile Substation expansion	**Harvest Mile Substation:** The existing 345 kV Harvest Mile Substation will be expanded to accommodate new 345 kV terminations and equipment. No new land acquisition is required for the expansion.

Note: For purposes of the Project cost estimates, the new Canal Crossing/Pawnee Substation expansion are included as part of Segment 2, but are represented in the Table in geographic, clockwise order for purposes of describing the Project.

Q. HOW IS THE REST OF YOUR TESTIMONY ORGANIZED?

A. In Section II below, I describe XES Transmission Project Management's project management and cost estimation processes. I explain how the Company develops its cost estimates for transmission and substation projects, including the assumptions that are used to develop estimates, and how the Company accounts for uncertainties and risks inherent in projects of this magnitude. I describe how the Company tracks project costs as work orders are opened and more engineering and construction work is performed. I also address issues related to the Company's cost estimation process that have been raised in recent transmission CPCN application proceedings.

In Section III, I provide the cost estimates for the Project. Costs for the Project are broken down into costs for the transmission line, substations, and land, consistent with Commission Rule 3102(b)(IV). As I discuss below, the Company is providing a more detailed cost estimate breakdown than what is required by Rule specified in the Rule 3102(b)(IV). The cost estimates rely on assumptions identified by Company witnesses, Mr. Byron R. Craig and Ms. Carly R. Rowe related to engineering and siting and land rights. I discuss the categories of costs included in the cost estimates and the risk reserve embedded in the estimates. Company witness, Ms. Brooke A. Trammell discusses the specific Commission findings the Company is requesting with respect to its cost estimates in this proceeding.

In Section IV, I discuss the 90-mile May Valley-Longhorn 345 kV transmission line extension (the "May Valley-Longhorn Extension," or "Extension"), that the Company is presenting in this CPCN filing for Commission consideration as an optional extension to its Pathway Project. Specifically, I present the Company's cost estimates associated with the May Valley-Longhorn Extension and anticipated 2025 in-service date for this option if the Commission issues a CPCN for it as part of this proceeding.

In Section V, I discuss the estimated sequencing and construction schedule for the Project, consistent with Commission Rule 3102(b)(V).

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

A. Yes, I am sponsoring the following five attachments:

- Attachment BJR-1 is a detailed cost estimate for the Pathway Project;
- Attachment BJR-2 is a monthly forecast cost estimate for the Pathway Project;
- Attachment BJR-3 is a detailed cost estimate for the May Valley-Longhorn Extension;
- Attachment BJR-4 is a monthly forecast cost estimate for the May Valley-Longhorn Extension; and
- Attachment BJR-5 is an estimated Project milestone schedule.

II. PUBLIC SERVICE'S PROJECT MANAGEMENT AND COST ESTIMATION PROCESSES

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 Public Service's project management expertise, and also explain the project management and cost estimation processes the Company's Transmission Project Management group uses to develop cost estimates for transmission and substation projects. I provide an overview of the Company's processes to develop cost estimates. I also describe the Company's process for developing its risk register to account for uncertainties and project risks. In addition, I describe how the Company tracks project costs as work orders are opened and more engineering and construction work is performed. I also address issues related to the Company's cost estimation process that have been raised in recent transmission CPCN application proceedings, including the "contingency" category that the Company has historically included in its cost estimates in CPCN applications and suggestions by Staff that the Company utilize AACE or ASTM standards or guidelines as benchmarks.

Q. PLEASE PROVIDE AN OVERVIEW OF THE KEY FUNCTIONS THE PROJECT MANAGEMENT TEAM WILL UNDERTAKE WITH RESPECT TO THIS PROJECT.

A. The Project Management team will be responsible for executing the Pathway Project from origination through Project close out. This will include managing the

Project Lifecycle process to develop, monitor, and control project scope, estimates/budget, schedule, and risks.

Q. GIVEN THE MAGNITUDE OF THIS PROJECT, ARE THERE ANY UNIQUE CONSIDERATIONS THE COMPANY NEEDS TO TAKE INTO ACCOUNT FROM A PROJECT MANAGEMENT PERSPECTIVE?

A. The quantity of both material and resources that will be needed to successfully execute a project of this size and duration will require additional upfront planning that will go beyond our normal business as usual processes. There will be early planning with our supply chain organization to leverage buying power and coordinate contracting strategies. This includes siting and land rights support, project management support, engineering, material procurement, and construction resources.

Q. WHY ARE YOU CONFIDENT THAT PUBLIC SERVICE WILL BE ABLE TO EFFECTIVELY MANAGE THE PATHWAY PROJECT?

A. As a vertically-integrated public utility with over a century of experience in developing and project managing electric, gas, and steam infrastructure throughout Public Service's Colorado territory and Xcel Energy's multi-state footprint, Public Service is extremely well-positioned to manage this particular project. To provide some overall perspective, currently the electric systems of all four of the Xcel Energy utilities are comprised of more than 20,000 miles of transmission lines and more than 1,200 substations across 10 states, serving 22,000 megawatts ("MW") of customer load. Development of transmission lines and substations are among our Company's core competencies and we have decades of experience in designing, constructing, operating and maintaining these facilities. The Company is also experienced in navigating the range of unique siting, permitting, engineering, and budgeting issues that transmission lines and substations present depending on the unique location and operational issues applicable to each facility. Our experience is augmented by strong partnerships with highly skilled, industry leading electrical contractors as well as specialized equipment and supply chain vendors. As I describe in detail below, we have robust cost estimation and project management processes in place to successfully manage projects from concept to execution, including risk identification, cost controls, and construction schedule management.

Q. CAN YOU PROVIDE EXAMPLES OF RECENT TRANSMISSION AND SUBSTATION PROJECTS WHICH THE COMPANY HAS SUCCESSFULLY EXECUTED?

A. Yes. Public Service has been in the business of designing, constructing, and project managing transmission and substation projects both small and large for decades. Public Service's more recent experience with complex, large-scale projects include: the 115-mile, 345 kV Pawnee-Daniels Park project plus substations, approved in Proceeding No. 14A-0287E; the Rush Creek Wind Project and 90-mile, 345 kV Rush Creek Gen-Tie plus substations, approved in Proceeding No. 16A-0117E; and the Cheyenne Ridge Wind Project and 70-mile, 345 kV Rush Creek Gen-Tie extension plus substations approved in Proceeding No. 18A-0905E. Additionally, Xcel Energy has successfully constructed hundreds of miles of 345 kV transmission lines across our other service territories, including as part of recently completed or ongoing projects in the upper Midwest, Texas, and New Mexico.

Q. PLEASE EXPLAIN HOW PUBLIC SERVICE DEVELOPS CPCN COST ESTIMATES FOR TRANSMISSION AND SUBSTATION PROJECTS.

A. Public Service follows Xcel Energy's internal policies and procedures for transmission project cost estimates, which are based upon generally accepted utility practices. The Company's Transmission Asset Management ("TAM") Estimating Procedures set forth the Company's standard process for developing cost estimates. In summary, to develop cost estimates for its capital projects (except for Indicative level estimates, which are the most preliminary), the Company utilizes a well-regarded software tool for developing cost estimates called InEight Estimate (formerly called "Hard Dollar Cost Management"). Company engineers use InEight Estimate to develop detailed cost estimates by entering historical cost data and other relevant information into the program, which then calculates a cost estimate using those inputs. InEight Estimate can be used by a range of industries to assist in estimating constructed costs of projects and facilities and is well-suited for use for electric utility transmission and substation projects.

InEight Estimate provides a framework to organize extensive cost component reference data, assemble estimates, manage multiple versions of the cost estimate calculation, and generate summary and detail reports for a variety of project types. The user builds their own database of components and activities suitable to their projects and populates and maintains the unit prices and other factors. The Company uses this tool in developing Scoping, Appropriations, and Engineering Estimates (which are increasingly more detailed, as discussed below) for its transmission line and substation projects.

A preliminary scope of work is created for a project based on that project's needs and benefits identified by the Company's Transmission Planning team. A multi-disciplinary project team is then chartered with members from the Company's Transmission Project Management, Transmission Planning, Engineering, Siting & Land Rights, Construction, Vegetation Management, and Supply Chain groups. This multi-disciplinary team develops a set of assumptions (e.g., line mileage, land acquisition and permitting requirements, environmental constraints, structure design, substation configuration, equipment procurement, labor, etc.).

There are typically four levels of project estimates that may subsequently be generated for each project, Indicative, Scoping, Appropriations, and Engineering Estimates. As the project progresses through its lifecycle from concept to construction, the level of refinement of the project's cost estimate improves as more of the work for the project is completed, for example, engineering and design, procurement, or contract bid and award. Similarly, as the project progresses, the project manager will have more detailed information related to siting and land rights activities, estimated material quantities, assumed equipment ratings and specifications, and unit prices for materials and labor. A brief description of each estimate level follows:

- **<u>Indicative Estimate (IE) Description:</u>**
  An Indicative Estimate carries no defined or implied level of accuracy and is based upon the estimator's experience, and is not developed for every project. It is typically an informal communication generally used for high-level alternative project comparisons and discussion. An Indicative Estimate is developed without use of the InEight Estimate software.

- **<u>Scoping Estimate (SE) Description:</u>**
  A Scoping Estimate is produced before engineering design and siting and land rights activities have begun or are only approximately 5 percent complete. This level of estimate is typically used as part of the Commission CPCN filings. The Company creates this using InEight Estimate software.

- **<u>Appropriations Estimate (AE) Description:</u>**
  An Appropriations Estimate refines a previously produced Scoping Estimate and improves the level of accuracy for budget and forecast purposes. It will be based on conditions expected to be encountered on the specific construction project and should include a site visit. The engineering and design work may be approximately 5-25 percent complete; the land acquisition work should generally be approximately 5-25 percent complete while permitting and siting work should be approximately 60-80 percent complete. This estimate is created using the InEight Estimate software.

- **<u>Engineering Estimate (EE) Description:</u>**
  An Engineering Estimate is the most accurate estimate created in the TAM process. It is created using InEight Estimate software. This estimate is prepared after due consideration of the construction site and inclusion of known extenuating circumstances. It includes the best material and equipment information available. Permitting, siting, and land acquisition work should be approximately 80-100 percent complete. The engineering should be approximately 75-100 percent complete; material costs are usually known; materials with long lead time items are usually ordered. At this stage, construction costs are still unknown, and remaining risks may be accounted for in the risk register.

Q. PLEASE EXPLAIN WHAT LEVEL OF ESTIMATE PUBLIC SERVICE PREPARED FOR THE PATHWAY PROJECT IN THIS CPCN APPLICATION.

A. The cost estimate provided with the CPCN application for the Pathway Project is best classified as a Scoping Estimate, as the Project cost estimate has been developed based on conceptual engineering design and before siting and land rights activities have begun. Public Service routinely presents scoping-level cost estimates to support its CPCN filings, with the Rush Creek Gen-Tie and Rush Creek Gen-Tie extension (Proceeding No. 16A-0117E and Proceeding No. 18A-0905E), Pawnee-Daniels Park Transmission Project (Proceeding No. 14A-0287E), Rifle-Parachute Transmission Project (Proceeding No. 13A-0032E), and Northern Greeley Area Transmission Project (Proceeding No. 17A-0146E) as recent examples.

I discuss the cost estimates for the Project in further detail in Section III, below.

Q. DOES THE COMPANY INCLUDE AN ADDITIONAL BUDGET CONTINGENCY ON TOP OF ITS TOTAL PROJECT COST ESTIMATE?

A. It has been the Company's past practice in CPCN application proceedings to propose a contingency range (generally stated as a percentage above and below the stated cost estimate) to the project cost estimate to account for uncertainty associated with the development and construction of its transmission and substation projects. The proposed range generally reflected the level of refinement the Company's Transmission Project Management team was able to achieve in its cost estimate at the time the CPCN application was filed.

However, given the confusion that has been caused by the Company's identification of a contingency range in recent CPCN application proceedings, and indications that including both a risk reserve and contingency in the Company's cost estimate is not useful for evaluating CPCN applications, the Company does not propose to include a contingency related to the Project's cost estimate.[3] As I explain below, the Company assigns specific risk reserve amounts for identified risks, and the risk reserve is part of the total cost estimate.

Q. HOW DOES THE COMPANY KEEP TRACK OF A PROJECT'S EXPENDITURES AND MONITOR THE ACCURACY OF ITS ESTIMATES?

A. The Company's Transmission Project Management group assigns a project manager to each project. The project manager is dedicated to working with the project team on a near daily basis to forecast the expenditures for a particular project, record expenses, modify expenses as needed through the life of a project, and compare actual performance to cost estimates. The project manager uses a Cost Analyst Report ("CAR"), which records the project's forecasted expenditures by category and tracks the actual costs. The CAR is generally a multi-sheet spreadsheet, in which there is a detailed record of monthly expenses by individual work order, and these costs are "rolled-up" into a summary presentation. The CAR is a "living document" that serves as a cost management tool until the project is complete and placed in service. The CAR tracks actual expenditures as well as forecasted spend for the duration of a project. The CAR is reviewed monthly to account for the actual spend amounts compared to the forecast and estimate at completion ("EAC"). The project team works with transmission leadership to

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[3] *See* Proceeding Nos. 19A-0728E & 20A-0063E, Decision No. C20-0648, at ¶¶ 50, 55 (discussing concepts of contingency and risk reserve); Proceeding No. 20A-0082E, Decision No. R20-0725, at ¶¶ 56-61 (discussing relationship between contingency and risk), *aff'd* Decision No. C20-0886, at ¶¶ 7, 19-24 (stating that the "estimated cost of the project plus projected variance is what we consider when determining whether to grant the CPCN").

continually evaluate ways to reduce project costs, even for projects tracking as forecasted.

Attachment BJR-1 to my Direct Testimony shows the Pathway Project's cost estimates aggregated into major cost categories for the five transmission line segments and seven substations. The major cost categories include Engineering, Permitting, Project Management; Land/Easements; Materials; Construction; Risk Reserve (related to each of these categories), and Overheads/Escalation. I discuss the cost estimates for the Project, and specific components of the Project, below in Section III.

Q. IS THERE A LEVEL OF UNCERTAINTY IN THE COMPANY'S COST ESTIMATES UNTIL THE ENGINEERING WORK, LAND ACQUISITION AND PERMITTING, AND CONSTRUCTION ACTIVITIES ARE COMPLETE?

A. Yes. A project's costs will never be completely known until all of the costs have been incurred. The Company is presenting its best estimate of costs to be incurred. The timing associated with the need for approvals from the Commission to implement large-scale projects and the regulatory lag associated with obtaining a CPCN, is one timing factor that will influence the estimate. Some level of uncertainty in the cost estimates will continue even after CPCN approval until the project is completed and placed in service. I discuss the Company's proposed semi-annual reporting in more detail below which will provide the Commission and stakeholders transparency as costs are incurred and estimates continue to be refined with the passage of time.

Q. HOW IS THIS UNCERTAINTY REFLECTED IN THE PROJECT'S COST ESTIMATE?

A. The Project's cost estimate includes dollar amounts for "risk reserve" for categories of costs where necessary expenditures may increase if a risk event occurs.

Q. HOW ARE THE RISK RESERVE AMOUNTS DEVELOPED?

A. The risk reserve amount reflects an assigned cost component for those anticipated risks at the time of cost estimation. A specific risk reserve amount is based on the estimated cost to incur the risk event and the probability of the risk event occurring. The risk reserve amount is typically determined based on a qualitative and quantitative evaluation of the activities and plans for the project, using the Company's engineers' experience with similar projects or project components. The risk events are identified in the project's risk register, which also records the dollar amounts assigned as the risk reserve.

Q. PLEASE DESCRIBE THE RISK REGISTER FURTHER.

A. A project's risk register is a document that records the potential risk events and assigns dollar amounts to be identified in the project's cost estimate as risk reserve. The risk register, including the identification of risks and the risk reserve amounts, is developed through a collaborative effort among the members of the multi-disciplinary project team. Risk reserve amounts are developed for individual risk items based on what the project team estimates would be required to address the specific risk.

In recognition of these variables and unknowns, the Company may assign a risk reserve based on the Company's assessment of such risks. Ms. Rowe describes the key land and permitting-related risks addressed in the risk reserve process in her Direct Testimony. Mr. Craig describes engineering design related risks addressed in the risk reserve process in his Direct Testimony. I discuss the risk reserve amounts embedded in the cost estimate for in this Project in more detail below.

Q. WHAT HAPPENS TO THE ALLOCATED RISK RESERVE AMOUNTS OVER TIME?

A. The risk reserve amounts are generally included in a project's internal budget approval process. The risk reserve is identified as a cost item in the project's CAR. The risk reserve is used (i.e., money is spent) when the identified risk occurs or is mitigated in some fashion. When this happens, costs incurred to address the risk event are recorded in the CAR. If an identified risk does not occur over the course of the project, the allocated risk reserve is typically moved to the Management reserve line item until all construction contracts are in place and civil engineering work has been completed. Then, the unused risk reserve dollars are removed from the project budget. For example, material cost risk may be removed once material contract costs been secured.

Q. PLEASE PROVIDE EXAMPLES OF TYPES OF RISKS THAT THE COMPANY INCLUDES A RISK RESERVE.

A. The Company includes a risk reserve to account for numerous types of risks it may encounter when constructing a project, including for instance, construction delays (which may be related to, among other things, supply or transport issues, hindrances encountered on the land, access to roads, or local jurisdiction permitting issues), problems with material supplies (including delivery timing, quality issues, or unanticipated equipment failure), fluctuations in prices of equipment (which may related to international tariffs, commodity price changes, and industry demand), weather-related delays or issues, licensing and permitting issues unique to the location (such as railroad licenses or jurisdictionally-mandated mitigation requirements), or changes in project scope due to unforeseen circumstances.

Q. IS THE INCLUSION OF RISK RESERVE AMOUNTS IN THE COST ESTIMATE A REASONABLE PRACTICE?

A. Yes. As with many construction projects, it is important to account for ways in which the final spend on a project is necessarily unknown. The use of risk reserve allows the Company to do so with some granularity for specific identified risks, based on the amount of engineering, siting and land rights activities, and other work the Company has completed at the time the cost estimate is developed. From a capital budgeting perspective, as well as considerations of due diligence and corporate governance, the identification of risk reserve amounts is reasonable and prudent management practice. I would note that risk management is a key component of prudent project management in general and is not unique or limited to the Company's approach to developing project cost estimates. For example, quantitative and qualitative risk management planning is considered a foundation of project management practice by the internationally recognized Project Management Institute ("PMI") and the Project Management Book of Knowledge

("PMBOK"), a collection of standard terminology and guidelines published by the PMI.

Q. IN YOUR EXPERIENCE, DOES THE COMPANY EMPLOY A TRANSMISSION PROJECT COST ESTIMATE DEVELOPMENT PROCESS THAT IS REASONABLE AND CONSISTENT WITH GOOD UTILITY PRACTICE?

A. Yes. As explained above, the Company's project cost estimating process is reasonable and consistent with good utility practice.

Q. WOULD YOU LIKE TO ADDRESS SUGGESTIONS BY STAFF IN RECENT CPCN APPLICATION PROCEEDINGS THAT THE COMPANY'S COST ESTIMATES SHOULD BE EVALUATED USING THIRD-PARTY STANDARDS AND GUIDELINES?

A. Yes. It is my understanding that Staff has suggested in recent CPCN application proceedings that the ASTM E2516 "Standard Classification for Cost Estimate Classification System" ("ASTM Standards") should be used to evaluate the Company's project cost estimates[4] and that Staff has also cited the AACE "International Recommended Practice No. 18R-97 Cost Estimate Classification System" ("AACE Practice") as a point of reference.[5]

As I described above, the Company has developed a cost estimation process that is specific to electric transmission projects and consistent with electric

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[4] *See* Proceeding No. 20A-0082E, Hr. Ex. 400, Adam Gribb Answer Testimony of Staff of the Colorado Public Utilities Commission ("Gribb Testimony") (filed July 2, 2020), Attachment AMG-5; Proceeding No 19A-0728E, Hr. Ex. 300, Adam Gribb Answer Testimony of Staff of the Colorado Public Utilities Commission ("Gribb Testimony") (filed Apr. 17, 2020) Attachment AMG-10.

[5] *See* Proceeding No. 20A-0082E, Hr. Ex. 400, Gribb Testimony, Attachment AMG-1; Proceeding No 19A-0728E, Hr. Ex. 300, Gribb Testimony, Attachment AMG-9.

utility practices. Public Service does not use the standards or practices identified by Staff in the Company's transmission capital planning process or across its businesses. It is my understanding that the ASTM Standards and the AACE Practice are not specific to utility projects and not designed for electric transmission projects like the Project here.

I also understand that the use of the ASTM Standards was recently rejected in Proceeding No. 20A-0082E, related to the Company's High Point Substation project. In that case, the administrative law judge ("ALJ") was "not persuaded by Staff's arguments that the ASTM Standards" should be used to evaluate cost estimates for the Company's electric transmission projects.[6] I am also unaware of any other Commission proceedings where either the ASTM Standards or the AACE Practice has been used or required.[7]

Staff has requested that the Company compare its Project cost estimate to the AACE cost estimate classification system. Although the Company does not use or endorse the use of the ASTM Standards or AACE Practice, based on my understanding of these standards and practices, I would say that the Company's current cost estimate is most consistent with a "Class 4" AACE estimate at this time. The Class 4 designation is comparable in my view to the Company's Scoping Estimate level I described above and most closely applicable to the Pathway Project given the cost estimates have been developed before engineering design

[6] Proceeding No. 20A-0082E, Decision No. R20-0725, at ¶ 60.
[7] *See id.* (finding that there was no reason to break with past Commission practice and evaluate CPCN cost estimates based entirely on ASTM Standards).

and siting and land rights activities have begun. As I noted above, Scoping level estimates are typically used as part of the Commission CPCN filings.

Q. WOULD YOU LIKE TO ADDRESS ANY OTHER ISSUES RAISED BY STAFF IN PRIOR CPCN PROCEEDINGS?

A. Yes. Staff has also expressed concern about the level of detail in the Company's cost estimates in recent CPCN application proceedings. Staff has stated that "[t]he kind of cost information Staff would expect to see in a CPCN application depends on the nature of the CPCN. Staff would expect information in the form of detailed line item budgets identifying equipment needed, labor costs, O&M expenses, land costs, overhead, risk reserve, etc. Where appropriate, Staff would also expect vendor quotes and contracts to be provided."[8] Although the Company continues to believe that the cost estimates it has provided with its CPCN applications, and the support provided for those cost estimates, are consistent with Commission Rule 3102(b)(IV), the Company understands Staff's concerns, particularly with respect to a project of this magnitude and complexity. We are therefore providing detailed cost estimate information for this CPCN filing, consistent with what Public Service has more recently provided in consolidated Proceeding Nos. 19A-0728E/20A-0063E and Proceeding No. 20A-0082E.[9] As I discuss below, Attachment BJR-1, includes many of the cost categories identified by Staff and provides much more granular data than is required by Rule 3102(b)(IV).

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[8] *See* Proceeding No. 20A-0082E, Hr. Ex. 400, Gribb Testimony, at 9:8-11; *see also* Proceeding No 19A-0728E, Hr. Ex. 300, Gribb Testimony, at 3:3-6 (stating substantially the same).

[9] *See* Proceeding No. 20A-0082E, Hr. Ex. 102, Rebuttal Testimony of Brooke A. Trammell, at 18:19–19:5 (filed Aug. 5, 2020); Hr. Ex. 103, Rebuttal Testimony of Byron R. Craig, at 29:4-9 (filed Aug. 5, 2020).

Q. IS THE COMPANY'S PROCESS USED TO DEVELOP COST ESTIMATES FOR TRANSMISSION PROJECTS REASONABLE AND APPROPRIATE?

A. Yes. The Company has developed its TAM Estimating Procedures based on many years of experience with constructing, developing, and project managing transmission projects across Public Service's footprint and Xcel Energy's multi-state footprint. For these reasons, I conclude that the TAM Estimating Procedures and resulting cost estimates we have developed for this proceeding are reasonable and appropriate.

III. PATHWAY PROJECT COST ESTIMATES

A. Overview

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

A. In this section of my Direct Testimony, I provide the total cost estimate for the Project, as well as for specific components as required by Rule 3102(b)(IV). I provide current cost estimates for the transmission line portion of the Project broken down into five segments, and for the substation portion of the Project broken down by each substation. The cost estimate information is further broken down by cost categories, which I discuss below. The cost estimates were developed using the assumptions identified by Company witnesses Mr. Craig and Ms. Rowe related to engineering and siting and land rights. I discuss the cost categories included in the estimates and the risk reserve amount embedded in the cost category estimates.

Q. WHAT IS THE OVERALL COST ESTIMATE FOR THE PATHWAY PROJECT?

A. The total cost estimate for the Pathway Project is approximately $1.695 billion. The cost estimate for the May Valley-Longhorn Extension is approximately $247 million, which I discuss in Section IV below.

Q. DO THESE FIGURES REPRESENT THE TOTAL TRANSMISSION COST PUBLIC SERVICE ANTICIPATES WILL BE NECESSARY TO IMPLEMENT ITS UPCOMING 2021 ELECTRIC RESOURCE PLAN & CLEAN ENERGY PLAN (“2021 ERP & CEP”)?

A. No. Company witness, Ms. King discusses the Company’s cost estimates for additional transmission investment that will be needed to implement the upcoming

2021 CEP & ERP, along with how more refined cost estimates will be brought forward to the Commission.

Q. WHAT DOES COMMISSION RULE 3102(b)(IV) REQUIRE WITH REGARD TO PROVIDING COST ESTIMATES IN CPCN APPLICATIONS?

A. Rule 3102(b)(IV) requires CPCN applications for transmission facilities to itemize estimated costs as land costs, substation costs and transmission line costs.

Q. PLEASE PROVIDE THE COST ESTIMATES IN THE CATEGORIES SPECIFIED BY RULE 3102(b)(IV).

A. Table BJR-D-2 shows the cost estimate broken down into the applicable categories, with land costs identified for the transmission line or substations.

Table BJR-D-2

Total Colorado's Power Pathway Project Cost Estimate*			
Cost item	**Estimated facilities cost****	**Estimated land cost**	**Total Estimate**
Transmission line	$ 1,258	$ 121	$1,379
Substations	$ 315	$1	$ 316
Totals	$ 1,573	$122	$ 1,695

* Costs are shown in millions.
** Costs for permitting, siting, and routing activities are included in the facilities costs.

I discuss the cost estimates for these categories in greater detail below.

B. Transmission Line Costs

Q. PLEASE DESCRIBE THE FACILITIES THAT WILL COMPRISE THE PATHWAY PROJECT'S TRANSMISSION LINE.

A. As described in more detail by Company witness Mr. Craig, the Project will generally be greenfield construction, consisting of approximately 560 miles of double-circuit 345 kV transmission line interconnecting at seven substations. As discussed in more detail in Section V below, Public Service is proposing to construct and in-service the Project in several phases. The entire transmission line will utilize the same structure design, which consists of single-pole, double-circuit tangent structures and two-pole dead-end structures. The pole height is expected to be in the range of 120 to 190 feet above the ground, with an average height of 135 feet for the tangents. The entire transmission line will have the same conductor design, which will be a two-bundle of 1272 kcmil ACSR "Bittern" in an 18" vertical configuration. The shield wires for the Project are two 48-count fiber optical ground wire which will support lightning and grounding protection and allow for communication to the substations.

Q. WHAT PORTION OF THE TOTAL PROJECT COST ESTIMATE IS ASSOCIATED WITH TRANSMISSION LINE (FACILITIES) COSTS?

A. The estimated costs for the transmission line facilities is $1.258 billion, or approximately 74 percent of the projected total cost (not including land costs).

Q. WHAT COSTS ARE INCLUDED IN THE PATHWAY PROJECT TRANSMISSION LINE COST ESTIMATE?

A. The Company generally aggregates individual cost components into the following major cost categories:

- **<u>Engineering, Permitting, Project Management</u>**: as also reflected in Attachment BJR-1:
    - **Engineering and Design**: This includes, for example, the hours needed to design the project and outside engineering contracts to support the design. Outside contracts can include soil exploration, design survey, storm water management plan design, project staking, and as-built survey.
    - **Permitting**: The Company must obtain necessary permits from jurisdictions the transmission line will traverse through. Costs in this category also include transmission line routing, public outreach and damage/settlement payments. Company witness Ms. Rowe discusses the Company's permitting and routing activities in more detail.
    - **Project Management**: This includes, for example, hours for the project management team to successfully execute the project. It includes project manager, scheduler, cost analysis, etc.
- **<u>Land / easements</u>**: The Company will acquire easements for the transmission line ROW. The activities associated with these costs are discussed in more detail by Company witness Ms. Rowe.
- **<u>Materials</u>**: The material elements that compose a transmission line, such as structures, conductor, insulators and foundations.
- **<u>Construction</u>**:
    - **Civil construction**: This includes, for example, access improvements, foundation installation, laydown yard improvements, and all material associated with this work.
    - **Electrical construction**: This includes, for example, all above ground installation. This is setting structures, stringing wires, splicing fiber, and grounding structures for all tasks required to complete construction. This also includes all material associated with this work.

- **<u>Overheads and Escalation</u>**:
  - **Administrative and General (A&G), Engineering and Supervision (E&S)**: Overhead costs (or indirect costs) are costs that are incurred but cannot be directly charged to a particular function.
  - **Purchase and Warehouse (P&W)**: A process to allocate authorized labor and nonlabor costs that are incurred to support the purchasing and warehousing functions.
  - **Escalation**: Represents the changes that accrue over time across cost categories. For example, it represents forecast wage increases that occur over the life of the project, or the cost of installed material price inflation in the economy.

Q. HOW DID THE COMPANY DEVELOP ITS COST ESTIMATES FOR THE TRANSMISSION LINE COMPONENT OF THE PROJECT?

A. Consistent with the process I described above in Section II, the Transmission Project Management group worked with a multi-disciplinary team, including the Company's transmission engineers to develop the cost estimate for the transmission line using the InEight Estimate software.

Q. WHAT ARE THE KEY ASSUMPTIONS THE COMPANY USED TO DEVELOP THE COST ESTIMATE FOR THE TRANSMISSION LINE?

A. As explained in detail in the Direct Testimony of Company witness Mr. Craig, the cost estimates for the transmission line have been developed based on assumptions regarding structure type and design, materials and commodity costs, labor resources, and soil conditions, to name a few. As explained in the Direct Testimony of Company witness Ms. Rowe, the cost estimates for the transmission line have been developed based on assumptions regarding transmission line mileage, right of way width, land costs based on current land use types, consulting and legal services, and permitting support services to name a few.

Q. DID THE COMPANY DEVELOP INDIVIDUAL COST ESTIMATES FOR EACH SEGMENT OF THE TRANSMISSION LINE?

A. Yes. Cost estimates for each of the five transmission line segments I identified in Table BRC-D-1 earlier in my testimony are provided in Attachment BJR-1.

Q. DOES THE COST ESTIMATE FOR THE TRANSMISSION LINE INCLUDE POTENTIAL RISK EVENTS?

A. Yes. As I described in Section II, in addition to the cost categories I identified above, the Transmission Project Management group develops a risk register to identify risks and create the risk reserve budget items. Based on the risk register developed for the Project, of the total transmission line cost estimate, approximately $310 million, or 22.5 percent, is risk reserve. The specific risk line items are aggregated in the same cost categories I identified above: Engineering, Permitting, Project Management; Land/Easements; Materials; and Construction. The items in the Overheads / Escalation category generally do not have associated risk reserve.

Q. PLEASE PROVIDE SOME EXAMPLES OF SPECIFIC TRANSMISSION LINE COSTS IN THE RISK RESERVE.

A. An example of risk reserve in the Permitting category the Project transmission line cost estimate pertains to the uncertainty regarding final routing. In the event the transmission line route for Segment 1 (once identified) is rejected or requires significant re-route due to external influences (e.g., local land use permit denial, inability to acquire a section of land rights along the route), the Company estimates that it would incur an additional $378,000 in permit costs if this risk event occurs.

Based on the Company's subject matter experts' experience, we assigned the probability of that risk event occurring at 85 percent. Therefore, the Company included as risk reserve in the cost estimate $321,300 for this category ($321,300 = $378,000 x 0.85). Another risk the Company identified is the possibility of civil construction requiring additional matting (*e.g.*, often used to support heavy construction equipment on unstable soil or wet areas), which may add cost. The Company assigned a cost of $5,000,000 as the amount of cost increase if such an event occurs. Based on the Company's subject matter experts' experience, we assigned the probability of that risk event occurring at 35 percent. The Company therefore included as risk reserve in the cost estimate $1,750,000 for this risk event ($1,750,000 = $5,000,000 x 0.35).

C. <u>Substation Costs</u>

Q. PLEASE DESCRIBE THE SUBSTATION FACILITIES THAT WILL BE CONSTRUCTED FOR THE PROJECT.

A. As I described above in Table BJR-D-1 above, the Project involves expansion of three existing substations (Fort St. Vrain, Pawnee, and Harvest Mile), expansion of a planned switching station (Tundra), and construction of three new switching stations (Canal Crossing [adjacent and interconnected to existing Pawnee Substation], Goose Creek [near and interconnected to Cheyenne Ridge wind facility generating stations], and May Valley [near but not interconnected to existing Lamar Substation]). Each substation will have new 345 kV line positions to accommodate the new 345 kV double-circuit transmission line and line/bus connected 345 kV shunt reactors. The specifications for each substation vary, depending on the needs of the particular location. The substation facilities are described in more detail in the Direct Testimony of Company witness, Mr. Craig.

Q. WHAT PORTION OF THE TOTAL PROJECT COST ESTIMATE IS ASSOCIATED WITH SUBSTATION FACILITIES COSTS?

A. The estimated costs for the substation facilities is $315 million, not including land costs.

Q. WHAT COSTS ARE INCLUDED IN THE SUBSTATION COST ESTIMATE?

A. The Company generally aggregates individual cost components into the following major cost categories:

- **Engineering, Permitting, Project Management**:
    - **Project Management**: Includes, but not limited to, labor roll up for Siting and Land Rights support and Project Management support.
    - **Permitting**: The Company must obtain necessary permits from jurisdictions where the substations will be located. Costs in this category also include substation siting and public outreach. The necessary permitting and siting activities are discussed in more detail by Company witness Ms. Rowe.
    - **Engineering and Design**: Includes, but not limited to, engineering labor for coordination and design activities as well as the external labor costs associated with other engineering design items, relay settings, special studies, Geotech and Surveys, and SWMP design.
- **Land / easements**: The Company will acquire land in fee for substation sites. The activities associated with these costs are discussed in more detail by Company witness Ms. Rowe.
- **Materials**: The elements that compose a substation, such as transformers, reactors, capacitor banks, circuit breakers, gang operated switches, bus, conductor, insulators, fencing, electrical equipment enclosures, protective relays, communication equipment, and foundations.

- **Construction**:
  - **Civil construction**: Includes, but not limited to, Construction and material costs associated with the installation of the substation below grade features and equipment. Examples being site development, yard surfacing, drive access, foundations, grounding, and detention ponds.
  - **Electrical construction**: Includes, but not limited to, Construction and material costs associated with the installation of the substation above grade equipment. Examples include structures, electrical equipment, buswork, switches, circuit breakers, capacitor banks, reactors, transformers, electrical equipment enclosure, station service, instrument transformers, raceway system.
  - **Commissioning**: Includes, but not limited to, labor costs associated with electrical equipment testing, pre-commissioning and commissioning activities, relay testing, SCADA testing, and switching and in-service activities.

- **Overheads and Escalation**
  - **Administrative and General (A&G), Engineering and Supervision (E&S)**: Overhead costs (or indirect costs) are costs that are incurred but cannot be directly charged to a particular function. The expenses should be assigned to all functions using an allocation method.
  - **Purchase and Warehouse (P&W)**: A process to allocate authorized labor and nonlabor costs that are incurred to support the purchasing and warehousing functions.
  - **Escalation**: Represents the changes that accrue over time across cost categories. For example, it represents forecast wage increases that occur over the life of the project, or the cost of installed material price inflation in the economy.

Q. HOW DID THE COMPANY DEVELOP ITS COST ESTIMATES FOR THE SUBSTATIONS?

A. As I described above in Section II, the Transmission Project Management group worked with a multi-disciplinary team, including the Company's transmission engineers, to develop the cost estimate for the proposed substations using the InEight Estimate software.

Q. WHAT ARE THE KEY ASSUMPTIONS THE COMPANY USED TO DEVELOP THE COST ESTIMATES FOR THE SUBSTATIONS?

A. Similar to the cost estimates for the transmission line, the cost estimates for the substations have been developed based on assumptions regarding substation design, facility costs, materials and commodity costs, and labor resources, among others, as explained by Company witness Mr. Craig. Company witness Ms. Rowe explains that the cost estimates for the land acquisition and related costs for the substation sites have been developed based on assumptions regarding the size of the parcel needed to accommodate the substations, land costs based on current land use types, and permitting and ancillary costs, among others.

Q. DID THE COMPANY DEVELOP INDIVIDUAL COST ESTIMATES FOR THE SUBSTATIONS?

A. Yes. Cost estimates for each of the substations I identified in Table BJR-D-1 earlier in my testimony are provided in Attachment BJR-1. Cost estimates for the Tundra Substation reflect only costs for the expansion of Tundra needed for the Colorado's Power Pathway Project. The pre-existing Tundra construction plans and costs are not part of this cost estimate, which, as Ms. Trammell explains, will be brought forward to the Commission in a forthcoming CPCN associated with interconnection facilities needed to implement the 2016 ERP's Colorado Energy Plan Portfolio.[10]

Q. DO THE COST ESTIMATES FOR THE SUBSTATIONS INCLUDE POTENTIAL RISK EVENTS?

A. Yes. As I described in Section II, in addition to the cost categories I discussed above, the Transmission Project Management group also develops a risk register to identify risks and create the risk reserve budget items. Of the total cost estimate for substations, approximately $52.3 million, or 16.5 percent, is risk reserve. The specific risk line items are aggregated in the same cost categories I identified above: Engineering, Permitting, Project Management; Land/Easements; Materials; and Construction. The items in the Overheads / Escalation category generally do not have associated risk reserve.

Q. PLEASE PROVIDE SOME EXAMPLES OF SPECIFIC SUBSTATION COSTS IN THE RISK RESERVE.

A. An example of a risk reserve item in the cost estimates for substations in the Engineering/Design category is with regard to the engineering and design for the new Goose Creek substation. Given the Project is in the conceptual engineering stage, in the event the design criteria and/or scope of work changes, additional costs could be incurred. If this risk event occurs, the Company estimates that it may incur an additional $150,000 in engineering costs. Based on the Company's engineers' experience, we assigned the probability of that risk event occurring at

[10] Attachment BJR-1 also identifies certain Project costs related to the Shortgrass (see Segment 3), Comanche (see Segment 4), and Daniels Park (see Segment 4) Substations. These costs are related to Project work at the Goose Creek and Tundra Substations, as explained by Company witness Mr. Craig.

60 percent. Therefore, the Company included as risk reserve in the cost estimate $90,000 for this category ($90,000 = $150,000 x 0.60). Another risk the Company identified is the possibility of material delivery delays that could impact construction productivity and schedule for the Goose Creek Substation. The Company assigned a cost of $1,000,000 as the amount of cost increase if such an event occurs. Based on the Company's subject matter experts' experience, we assigned the probability of that risk event occurring at 30 percent. The Company therefore included as risk reserve in the cost estimate $300,000 for this risk event ($300,000 = $1,000,000 x 0.30).

D. <u>Land Costs</u>

Q. PLEASE DESCRIBE THE LAND RIGHTS THE COMPANY WILL NEED TO ACQUIRE FOR THE PROJECT.

A. As explained by Company witness Ms. Rowe, the Project will generally require acquisition of a 150-foot-wide right-of-way ("ROW") for the transmission line. The Company will also acquire additional land in fee for the new Goose Creek Substation and the new May Valley Substation. Existing Company-owned property will be utilized for expansions and new facilities required at Fort St. Vrain, Pawnee, Canal Crossing (which will be located adjacent to Pawnee), Tundra, and Harvest Mile substations.

Q. WHAT PORTION OF THE TOTAL PROJECT COST ESTIMATE IS ASSOCIATED WITH LAND RIGHTS AND RELATED COSTS?

A. The estimated costs for the land-related rights and activities is $123 million of which $122 million is for the transmission line and $1 million is related for the substations.

Q. WHAT COSTS ARE INCLUDED IN THE LAND COST ESTIMATE?

A. The land-related cost estimate includes the acquisition of the 150-foot-wide ROW for the transmission line through non-exclusive easement agreements, fee acquisition of land for the new substation sites, and personnel costs associated with the land rights acquisition. Other examples of land costs not including the easement and fee acquisition costs are discussed in the Direct Testimony of Ms. Rowe and include, for example, real estate market analyses, title work, and land survey.

Q. HOW DID THE COMPANY DEVELOP ITS ESTIMATES FOR THESE COSTS?

A. As I described above in Section II, the Transmission Project Management group worked with a multi-disciplinary team, including personnel from the Company's Siting and Land Rights group to develop its Project cost estimates using the InEight Estimate software. Company witness Ms. Rowe identifies the key assumptions used by the Company to develop the cost estimates for the land rights acquisition and other land-related activities.

Q. DID THE COMPANY DEVELOP LAND COST ESTIMATES FOR DISCRETE SEGMENTS OF THE TRANSMISSION LINE AND THE INDIVIDUAL SUBSTATIONS?

A. Yes. Cost estimates for land-related costs associated with each of the five transmission line segments and for each substation I identified in Table BJR-D-1 above are included in the Land/Easement line item of Attachment BJR-1.

Q. DOES THE COST ESTIMATE INCLUDE POTENTIAL RISK EVENTS?

A. Yes. As I described in Section II, in addition to the cost categories I identified above, the Transmission Project Management group also develops a risk register to identify risks and create the risk reserve budget items. Of the total estimate of land rights acquisition and other land-related costs, approximately $45 million, or 37 percent, is risk reserve. Company witness Ms. Rowe discusses the key land rights acquisition risks as well as permitting-related risks. In addition, Ms. Rowe provides examples of land rights acquisition risks that were developed in the risk register and are included in the risk reserve amount for land costs.

Q. PLEASE PROVIDE SOME EXAMPLES OF SPECIFIC COSTS IN THE RISK RESERVE.

A. One example of a risk reserve item in the cost estimate for land rights acquisition costs for Segment 1 (Fort St. Vrain to Canal Creek) relates to the potential for the cost to acquire easements for the transmission line ROW being higher than estimated. If this risk event occurs, the Company estimates that it would incur an additional $7,300,000 in easement costs. Based on the Company's Siting and Land Rights staff experience, we assigned the probability of that risk event occurring at 50 percent. Therefore, the Company included as risk reserve in the cost estimate $3,650,000 for this category ($3,650,000 = $7,300,000 x 0.50). Another risk the Company identified on this same segment is the possibility of transmission line lengths increasing by 20 percent, which would occur if the transmission line must be routed over a longer physical distance. The Company assigned a cost of $2,000,000 as the amount of cost increase if such an event occurs. Based on the Company's Siting and Land Rights staff experience, we assigned the probability of that risk event occurring at 50 percent. The Company therefore included as risk reserve in the cost estimate $1,000,000 for this risk event ($1,000,000 = $2,000,000 x 0.50).

E. Semi-Annual Reporting

Q. HOW DOES THE COMPANY PROPOSE TO INFORM THE COMMISSION OF FUTURE CHANGES TO ITS PROJECT COST ESTIMATES AS THE PROJECT DEVELOPS?

A. As described in the Direct Testimony of Ms. Trammell, while the Commission's Rules do not require reporting on projects that are granted a CPCN, the Commission has in the past required semi-annual reporting for projects of larger or more complex magnitudes. These semi-annual reports provide updates and transparency to the Commission and stakeholders as project cost estimates inevitably change from the time a CPCN is granted to completion of construction. Public Service proposes to report on the Pathway Project in a manner similar to that recently approved by the Commission in Consolidated Proceeding No. 19A-0728E/20A-0063E.

Q. PLEASE DESCRIBE THE CONTENTS OF THE SEMI-ANNUAL REPORTS THE COMPANY PROPOSES TO PROVIDE FOR THE PATHWAY PROJECT.

A. The Company proposes to provide the same detailed information for the Pathway Project as what was proposed and approved in Consolidated Proceeding No. 19A-0728E/20A-0063E, including:

- monthly actual expenses incurred and monthly budgeted expenditures by activity for major expense categories by segment;
- any modifications, by month, to subsequent forecasted expenditures for the remainder of the Project;
- a cumulative comparison of actual costs to estimated costs for the Project;
- an explanation of any material changes to the overall cost estimate for the Project;
- an explanation of any material changes to the installation schedule for the Project;
- an explanation of efforts to reduce costs;
- a narrative statement of the status of the overall Project; and
- an overall project progress exhibit that presents project schedule and actual project progress for major milestones including, but not limited to, land use permits from local government(s), acquisition of property rights, major equipment procurements and purchases, and construction progress, testing, commissioning and commercial operations.

The Company will provide the reporting details listed above for each of the five Project segments consistent with the cost estimate framework of Attachment BJR-2 of my Direct Testimony.

Q. WHEN WOULD THE COMPANY PROVIDE THE SEMI-ANNUAL REPORTS?

A. The Company proposes to file the first semi-annual report 90 days after the Commission's final decision in this proceeding and the second semi-annual report six months later. The semi-annual reporting will continue for the duration of the Project and will conclude within six months after all Project segments are placed in service.

F. Consideration of Future Related Costs

Q. WILL THE COMPANY INCUR COSTS IN THE FUTURE RELATED TO THE PROJECT, BUT WHICH ARE NOT INCLUDED IN THE PROJECT COST ESTIMATES?

A. Yes. The Project facilities and the related Project cost estimates do not account for certain facilities and devices that may need to be installed when generation facilities are interconnected to the Pathway Project. Once the Company knows which generation facilities will be interconnected, it will be able to identify what additional facilities and devices are necessary and develop cost estimates accordingly. Company witnesses Ms. Trammell and Ms. King discuss the need and timing for follow-up CPCN applications and the related costs.

IV. MAY VALLEY-LONGHORN EXTENSION

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

A. The purpose of this section of my Direct Testimony is to describe the May Valley-Longhorn Extension option and the associated costs should the Commission issue a CPCN for it.

Q. PLEASE PROVIDE AN OVERVIEW OF THE MAY VALLEY-LONGHORN EXTENSION.

A. The Company is also presenting for Commission consideration in this proceeding a 90-mile, 345 kV double circuit transmission line that would extend from the southeastern corner of the Pathway Project at the new May Valley Substation south to a new Longhorn Substation near Vilas. A vicinity map of the May Valley-Longhorn Extension is provided as Attachment ARK-2 to the Direct Testimony of Company witness, Ms. King. The Company is bringing forward this May Valley-Longhorn Extension to the Pathway Project for the Commission's consideration, as it would establish additional transmission interconnection opportunities for potential renewable generation developers in the wind-rich southeastern area of the state. The Company anticipates that having a well-planned double-circuit transmission line to this area would not only facilitate clean energy resource development, but would also minimize the potential likelihood of clean energy project developers needing to construct multiple generation tie lines in this region to interconnect to the Pathway Project 345 kV transmission backbone.

Q. PLEASE DESCRIBE THE FACILITIES THAT WOULD COMPRISE THE MAY VALLEY-LONGHORN EXTENSION.

A. The facilities associated with this extension option include two additional line terminations at the Pathway Project's May Valley Substation, approximately 90 miles of double circuit 345 kV transmission line, and a new Longhorn Substation near Vilas.

Q. WHAT IS THE COMPANY'S COST ESTIMATE FOR THE MAY VALLEY-LONGHORN EXTENSION?

A. The estimated cost for the May Valley-Longhorn Extension is $247 million. Table BJR-D-3 shows the cost estimate for the May Valley-Longhorn Extension broken down into the categories specified by Rule 3102(b)(IV), with land costs identified for the transmission line or substation.

Table BJR-D-3

Total May Valley-Longhorn Extension Cost Estimate*			
Cost item	**Estimated facilities cost****	**Estimated land cost**	**Total Estimate**
Transmission line	$ 194	$ 9	$ 203
Substations	$ 43	$ 1	$ 44
Totals	$ 237	$ 10	$ 247

* Costs are shown in millions.
** Costs for permitting are included in the facilities costs

Q. WHAT COSTS ARE INCLUDED IN THE MAY VALLEY-LONGHORN EXTENSION ESTIMATE?

A. The cost categories for the May Valley-Longhorn Extension are generally the same as the categories I described earlier for the Pathway Project transmission line, substations, and land (in Sections III.B, III.C, and III.D, respectively).

The cost estimates were developed in the same manner as the Pathway Project's cost estimates using the same types of assumptions. Similar to the cost estimates for the transmission line, substations, and land for the Pathway Project, a risk register was also developed that identifies risks and creates the risk reserve budget items. Of the total cost estimate for the May Valley-Longhorn, approximately $48 million, or 19 percent, is risk reserve. The specific risk line items are aggregated in the same cost categories I have identified above: Engineering, Permitting, Project Management; Land/Easements; Materials; and Construction. The items in the Overheads / Escalation category generally do not have associated risk reserve.

Q. PLEASE PROVIDE AN EXAMPLE OF SPECIFIC COSTS IN THE RISK RESERVE FOR THE MAY VALLEY-LONGHORN EXTENSION.

A. One example of a risk reserve item in the May Valley-Longhorn Extension cost estimate relates to the transmission line and subsurface and soil unknown impacting constructability. If this risk event occurs, the Company estimates that it would incur an additional $2,000,000 in engineering costs. Based on the Company's engineers' experience, we assigned the probability of that risk event occurring at 40 percent. Therefore, the Company included as risk reserve in the cost estimate $800,000 for this category ($800,000 = $2,000,000 x 0.40).

Q. WILL THE COMPANY'S SEMI-ANNUAL REPORTS THAT YOU DESCRIBED EARLIER IN YOUR TESTIMONY INCLUDE REPORTING ON THE MAY VALLEY-LONGHORN EXTENSION IF THE COMMISSION APPROVES THE EXTENSION AS PART OF THIS CPCN APPLICATION?

A. Yes. If the Commission grants a CPCN for the Company to construct the May Valley-Longhorn Extension, the Company will provide the same detailed reporting information for the Extension that I listed in Section III.E., of my testimony for the Pathway Project.

V. PROJECT SEQUENCING, SCHEDULE, AND CONSTRUCTION PLAN

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

A. In this section of my Direct Testimony, I describe the anticipated Project schedule, construction plans, and in-service date of the Pathway Project and May Valley-Longhorn Extension. I also identify the timing and sequencing of key milestones for the Pathway Project and May Valley-Longhorn Extension.

Q. WHAT IS THE ANTICIPATED CONSTRUCTION START DATE AND ESTIMATED CONSTRUCTION PERIOD FOR THE PATHWAY PROJECT?

A. For Segments 2 (Canal Crossing to Goose Creek) and 3 (Goose Creek to May Valley) and the associated Pawnee, Canal Crossing, Goose Creek, and May Valley Substations construction will start in 2023 with an estimated two-year construction duration. For Segment 1 (Fort St. Vrain to Canal Crossing) and the Fort St. Vrain Substation, construction will start in 2024 with an estimated two-year construction duration. For Segments 4 (May Valley to Tundra) and 5 (Tundra to Harvest Mile) and the associated Tundra and Harvest Mile Substations, construction will start in 2025 with an estimated two-year construction duration. Attachment BJR-5 provides an estimated visual depiction of the Company's proposed sequencing and schedule milestones for the Project.

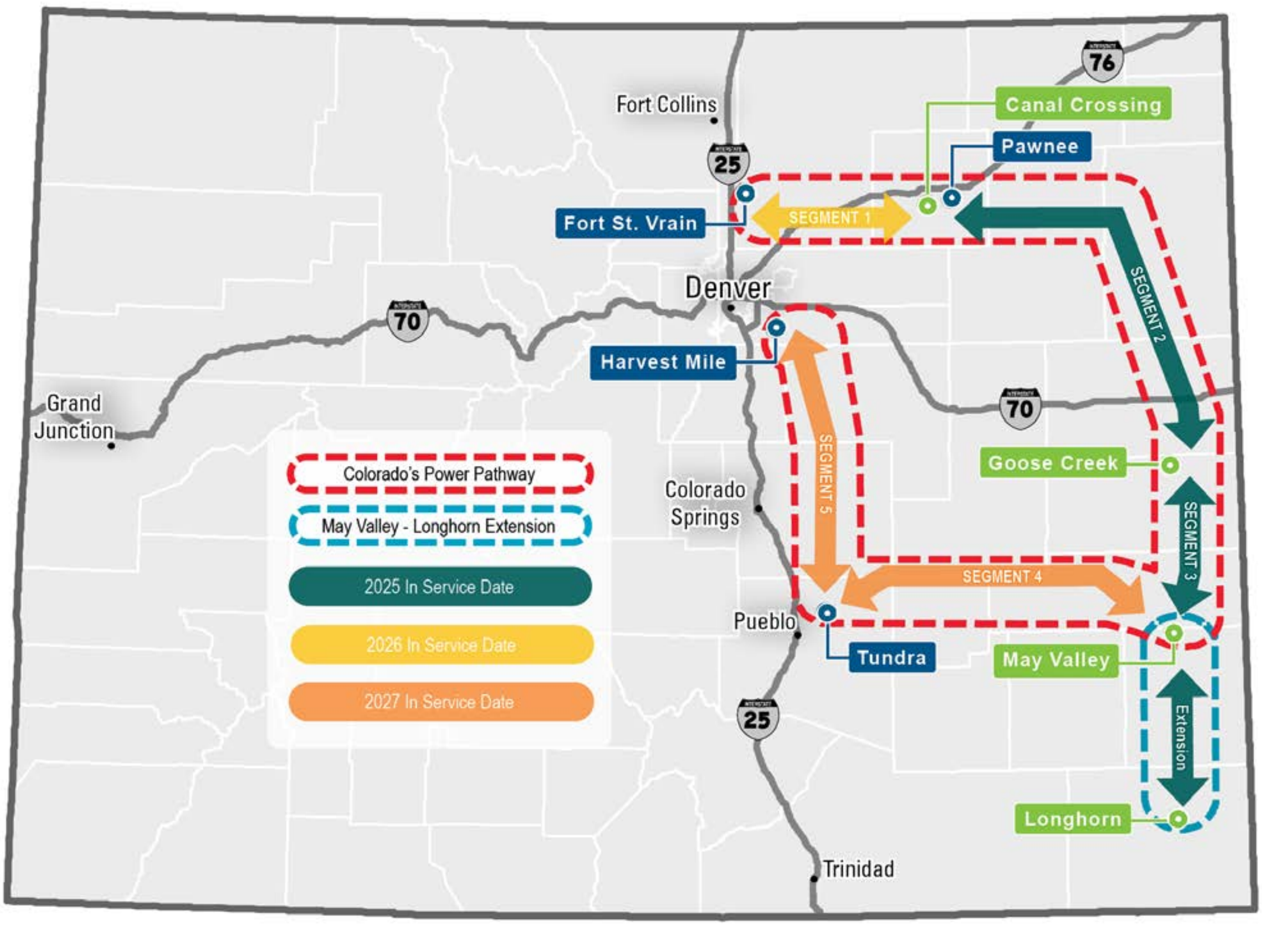
Q. WHAT IS THE ESTIMATED IN-SERVICE DATE FOR THE PROJECT?

A. The estimated in-service dates for the Project facilities are summarized in Table BJR-D-4 and provided as a visual depiction in Figure BJR-D-1 below.

1 **Table BJR-D-4**

Project Facilities	Estimated In-Service Date (by end of year)
Segments 2, 3 and Pawnee, Canal Crossing, Goose Creek, and May Valley Substations	2025
Segment 1 and Fort St. Vrain Substation	2026
Segments 4, 5 and Tundra and Harvest Mile Substations	2027

2 **Figure BJR-D-1: Estimated In-Service Dates by Project Segment**



Q. WHAT FACTORS HAVE INFORMED THE COMPANY'S PLANNED SEQUENCING?

A. The planned sequencing for the construction and in-service dates for the Pathway Project are informed by several factors, including the Company's upcoming 2021 ERP & CEP and the expiration of Federal tax credits for wind and solar development (and the related need for generation development to be in-service before the 2025 expiration), as discussed in more detail by Company witness Mr. Hill; the reliability benefits from networking the existing radial Gen-Tie, as discussed in more detail by Company witness Ms. King; and the potential for more challenging routing and permitting activities that may be required for Segment 5 (Tundra to Harvest Mile).

Q. WHAT WOULD BE THE ANTICIPATED CONSTRUCTION SCHEDULE AND IN-SERVICE DATE FOR THE MAY VALLEY-LONGHORN EXTENSION, IF APPROVED IN THIS PROCEEDING?

A. The planned in-service date would be the end of year 2025, coinciding with the planned in-service date for Segments 2 and 3 and the related substations, including the May Valley Substation where the May Valley-Longhorn Extension would interconnect with the Pathway Project.

Q. WHAT FACTORS MAY IMPACT THE ESTIMATED CONSTRUCTION SCHEDULE?

A. There are many variables that factor into the construction schedule for projects of this magnitude. One key variable that may impact the construction schedule is the timing of final siting and routing for each Project Segment and acquiring all necessary land rights and permits. Ms. Rowe describes these siting and land rights activities and the general anticipated timeframe for these activities in her Direct Testimony. Other construction timing variables include engineering design or scope changes that may occur over the course of Project development, and the timing of equipment procurement. As I discussed earlier in my testimony, construction schedule management is a fundamental component of the Company's overall project management and risk assessment processes and the Company's deep project management experience positions us well to successfully manage the estimated in-service dates and construction sequencing of the Pathway Project.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Statement of Qualifications

Brian Richter

Mr. Richter is currently the Senior Manager of Transmission Project Management in Xcel Energy's Electric Transmission organization. In this role, Mr. Richter directs project/portfolio managers in the full scope of their responsibilities associated with extremely large and complex substation and transmission line projects, including directing the project/portfolio manager's role (definition of schedule, budget, implementation risk, change, opportunity and resource allocation management) for extremely complex projects, portfolios and programs and providing strategic and tactical project/portfolio implementation advice and direction. Mr. Richter develops and directs implementation processes for the multi-year Transmission project/portfolio plans and manages project/portfolio managers to ensure that the plans are implemented within scope, timing, and forecast guidelines. Mr. Richter also provides strategic and tactical guidance regarding public and regulatory issues that are encountered during project/portfolio implementation.

Mr. Richter has over 20 years of experience in the electric power industry, including general management, project management, design and standards. He has provided strategic direction as well as engineering and project management for a broad range of utility programs, projects, and studies associated with distribution, substations, and transmission. Mr. Richter received a Bachelor of Science in Electrical and Computer Engineering from The Ohio State University. He is a registered professional engineer in Colorado.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR COLORADO'S POWER PATHWAY 345 KV TRANSMISSION PROJECT AND ASSOCIATED FINDINGS REGARDING NOISE AND MAGNETIC FIELD REASONABLENESS	) PROCEEDING NO. 21A-XXXXE

AFFIDAVIT OF BRIAN J. RICHTER ON BEHALF OF PUBLIC SERVICE COMPANY OF COLORADO

I, Brian J. Richter, 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 Denver, Colorado, this 1st day of March, 2021.

Brian Richter, Senior Manager, Transmission Project Management

Subscribed and sworn to before me this 1st day of March, 2021.

Amanda Clark
Notary Public

My Commission expires 3/25/2024

AMANDA CLARK
Notary Public
State of Colorado
Notary ID # 20164004880
My Commission Expires 03-25-2024