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 APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN	**)))))**	**PROCEEDING NO. 21A-____E**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF HARI SINGH</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

March 31, 2021

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

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<u>TABLE OF CONTENTS</u>

<u>SECTION</u> **<u>PAGE</u>**

LIST OF ATTACHMENTS

Attachment HS-1	Colorado Transmission System Map (2020)
Attachment HS-2	2020 Amended Ten-Year Transmission Report and Supplemental Report
Attachment HS-3	Vicinity Map of Colorado's Power Pathway 345 kV Transmission Project
Attachment HS-4	Vicinity Map of the May Valley-Longhorn Extension to Colorado's Power Pathway
Attachment HS-5	Colorado Coordinated Planning Group's 80x30 Task Force Report

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2021 ERP & CEP	Public Service's 2021 Electric Resource Plan and Clean Energy Plan
ALJ	Administrative Law Judge
BES	Bulk Electric System
CCPG	Colorado Coordinated Planning Group
CEPP	Colorado Energy Plan Portfolio
Commission	Colorado Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
DCS	Disturbance Control Standard
ECA	Energy Commodity Adjustment
ERO	Electric Reliability Organization
ERP	Electric Resource Plan
ERZ	Energy Resource Zones
EVRAZ	CF&I Steel, L.P. d/b/a EVRAz Rocky Mountain Steel
FERC	Federal Energy Regulatory Commission
HVDC	High Voltage Direct Current
IBR	Inverter-Based Resources
ITC	Investment Tax Credit
ISO	Independent System Operator
ISO-NE	Independent System Operator New England

Acronym/Defined Term	**Meaning**
Joint Utilities	Black Hills Energy, Tri-State Generation and Transmission Association, Inc, And Public Service Company of Colorado
kV	Kilovolt
LGIP	Large Generator Interconnection Procedure
MVA	Megavolt-Ampere
MVAr	Megavolt-Ampere Reactive
MW	Megawatt
NERC	North American Electric Reliability Corporation
OATT	Open Access Transmission Tariff
Pathway Project or Project	Colorado’s Power Pathway 345 kV Transmission Project
PJM	PJM Regional Transmission Organization
PRPA	Platte River Power Authority
PTC	Production Tax Credit
Public Service or Company	Public Service Company of Colorado
RMR	Reliability Must-Run
ROCOF	Rate of Change Of Frequency
RTO	Regional Transmission Organization
San Luis Valley Project	San Luis Valley-Poncha 230 kV Transmission Project
SB07-100	Senate Bill 07-100
SCR	Short Circuit Ratio
StatCom	Static Compensator

Acronym/Defined Term	**Meaning**
Tri-State	Tri-State Generation and Transmission Association, Inc.
WAPA-RMR	Western Area Power Administration-Rocky Mountain Region
WECC	Western Electricity Coordinating Council
XES	Xcel Energy Services Inc.
Xcel Energy	Xcel Energy Inc.

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DIRECT TESTIMONY AND ATTACHMENTS OF HARI SINGH

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, AND RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Hari Singh. My business address is 1800 Larimer Street, Denver, Colorado, 80202.

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

A. I am employed by Xcel Energy Services (“XES”) as Principal Engineer in Public Service Company of Colorado’s (“Public Service” or the “Company”) Transmission Planning group. XES is a wholly owned subsidiary of Xcel Energy Inc. (“Xcel Energy”) and provides an array of support services to Public Service 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 am responsible for performing, reviewing, and supervising the reliability studies and assessments of the Company’s transmission system to determine the future need and benefits of transmission reliability improvements and transmission expansion plans. In a previous position, I have also performed and reviewed such studies and assessments for the operations time horizon, which spans operations planning activities from day-ahead to weeks-ahead timeframes in preparation for real-time operations reliability. The Company uses these studies to prudently manage any transmission reliability risks identified in operations and/or planning horizons by developing technically and cost-effective mitigation actions needed to maintain an adequate level of reliability. A more detailed description of my qualifications is set forth in my Statement of Qualifications at the conclusion of my Direct Testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to support the Company's 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP") from a transmission planning perspective.

In Section II of my Direct Testimony, I discuss the Company's compliance with Rule 3608 of the Colorado Public Utilities Commission's ("Commission") existing Electric Resource Plan ("ERP") rules and provide an overview of Public Service's transmission system and system capabilities. I also provide an overview of the Company's transmission planning process.

In Section III, I discuss the interrelationship of the 2021 ERP & CEP with Colorado's Power Pathway Project 345 kilovolt ("kV") Transmission Project (the "Pathway Project") for which the Company filed an Application for a Certificate of Public Convenience and Necessity ("CPCN") on March 2, 2021 in Proceeding No.

21A-0096E. I discuss the Company's identification of the Pathway Project as a transmission backbone project that will enable the interconnection of resources proposed by generation developers as part of their bids submitted in response to the 2021 ERP & CEP's Phase II competitive solicitation. As discussed in the Direct Testimony of Company witness Ms. Brooke A. Trammell, the Pathway Project will provide bidders with the certainty of backbone transmission infrastructure in an area of the state that is rich with renewable resource development potential.

Next, I sponsor the Company's 2020 Amended Ten-Year Transmission Report and Supplemental Report (prepared pursuant to Rule 3627 Report and filed in Proceeding No. 20M-0008E) as Attachment HS-2 to my Direct Testimony, and explain why none of the "conceptual projects" identified in the Report, including the San Luis Valley Project, should be designated as planned transmission projects in the manner contemplated under the Joint Transmission Proposal, as was presented and considered in Proceeding No. 19R-0096E, for purposes of the Company's 2021 ERP & CEP resource solicitation process.

In Section IV, I discuss the transmission reliability review and planning process that has occurred to support the 2021 ERP & CEP and explain that evaluating and planning for transmission reliability is an iterative, ongoing, and continual process that occurs before, during, and after the ERP regulatory process. I additionally discuss how the Company uses must-run designations as a tool to maintain system reliability, and how the Company's must-run designations usage may be influenced or impacted by the generation portfolio approved as part of this 2021 ERP & CEP. I also describe the future transmission system reliability performance studies that will occur to determine additional transmission facilities (e.g., reactive support, grid strength reinforcement, network upgrades, and interconnection facilities) and related investments that will be necessary to accommodate the portfolio ultimately approved in Phase II of the 2021 ERP & CEP.

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

A. Yes. I am sponsoring the following attachments which were prepared by me or under my direct supervision or are a complete and accurate copy of the documents I represent them to be:

- Attachment HS-1 is an overview map of the Colorado Transmission network by ownership;
- Attachment HS-2 is the 2020 Amended Ten-Year Transmission Report and Supplemental Report filed in Proceeding No. 20M-0008E;
- Attachment HS-3 is a vicinity map for the Pathway Project;
- Attachment HS-4 is a vicinity map for the May Valley-Longhorn Extension of the Pathway Project; and
- Attachment HS-5 is the Colorado Coordinated Planning Group's 80x30 Task Force Report.

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR DIRECT TESTIMONY?

A. I recommend the Commission not designate any of the Company's conceptual transmission projects as planned transmission projects—as that term was contemplated in the Joint Transmission Proposal filed in Proceeding No. 19R-0096E—for purposes of the Phase II bid solicitation in this 2021 ERP & CEP proceeding. However, as explained by Company witness Ms. Trammell in her Direct Testimony, bidders may propose to interconnect to the Pathway Project without taking on an additional transmission cost burden in the levelized energy cost of their bids.

II. TRANSMISSION SYSTEM & TRANSMISSION PLANNING OVERVIEW

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

A. In this section of my Direct Testimony, I outline how the Commission's existing ERP rules address transmission planning and identify the Company's compliance with Rule 3608 in this 2021 ERP & CEP. I then provide an overview of the transmission system in Colorado and describe the transmission planning process.

Q. PLEASE SUMMARIZE HOW THE COMMISSION'S CURRENT ERP RULES REQUIRE THE COMPANY TO ADDRESS TRANSMISSION IN ITS ERP FILING.

A. Rule 3608 is the Commission's primary ERP rule that sets forth how the Company is to address transmission resources in an ERP filing. The Company has detailed its compliance with Rule 3608 in Volume 2 (Attachment AKJ-2) of its 2021 ERP & CEP. To summarize, though, among other things, Rule 3608 requires that Public Service: (a) report on existing transmission capabilities, and future needs during the planning period for facilities 115 kV and above; (b) generally identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of resources; (c) submit a description of all transmission lines and facilities appearing in its most recent Rule 3627 Report filed with the Commission that could reasonably be placed into service during the resource acquisition period, including pertinent details about each facility; (d) consider transmission costs required by or imposed on the system by the transmission benefits provided by a particular resource as part of the bid evaluation criteria; and (e) describe and estimate the cost of all new transmission facilities associated with any specific resources proposed for acquisition other than through a competitive acquisition process.

Q. HAS THE COMPANY COMPLIED WITH RULE 3608?

A. Yes. In addition to discussing some of this information below in my Direct Testimony, Volume 2 of the 2021 ERP & CEP contains detailed information consistent with Rule 3608.

Q. PLEASE PROVIDE AN OVERVIEW OF PUBLIC SERVICE'S TRANSMISSION SYSTEM IN COLORADO.

A. As of 2020, Public Service owns and maintains approximately 4,867 circuit-miles of transmission lines, all of which are located in Colorado. The transmission lines are rated 44 kV, 69 kV, 115 kV, 138 kV, 230 kV, and 345 kV. The Company also uses 236 transmission and distribution substations to transform and deliver electric energy.

Colorado is on the eastern edge of the Western Interconnection, which operates asynchronously from the Eastern Interconnection. The Public Service–Southwestern Public Service Company Tie-line and the 210 Megawatt ("MW") High Voltage Direct Current ("HVDC") back-to-back converter station, in-service since December 31, 2004, provides the only link in Colorado between the two Interconnections. In addition to the transmission facilities solely owned by the Company, Public Service has ownership in the jointly-owned western slope transmission facilities extending from the Craig/Hayden area in Northwestern Colorado to the Four Corners area in Southwestern Colorado. Attachment HS-1 to my Direct Testimony shows a map of the 2020 Colorado Transmission System, including Public Service's transmission facilities.

Q. PLEASE DESCRIBE THE TRANSMISSION PLANNING PROCESS IN THE STATE OF COLORADO.

A. The transmission planning process in Colorado is intended to facilitate the identification and development of electric infrastructure in a manner that maintains reliability and meets load growth. Each Transmission Provider in the state is generally responsible for planning its own transmission system, subject to the Commission's coordinated transmission planning regulatory framework. To ensure this process is as seamless and efficient as possible, and consistent with the coordinated, open, and transparent transmission planning on local and regional (including sub-regional) levels required by FERC Order 890, Public Service participates in collaborative transmission planning at sub-regional and regional levels. All of the Transmission Providers in Colorado belong to the sub-regional transmission planning group known as the Colorado Coordinated Planning Group ("CCPG"). CCPG was formed in 1991 and is a planning forum that operates to assure a high degree of reliability through joint planning, development and operation of high voltage transmission located in the Rocky Mountain Region. CCPG meets on a regular basis to discuss coordinated transmission planning in an open stakeholder process.

Q. PLEASE DESCRIBE THE COMMISSION'S RULE 3627 TRANSMISSION FILING REQUIREMENT.

A. Rules 3625-3627 set forth the process for planning and coordinating additional electric transmission in Colorado. Notably, Rule 3627 requires that each even year, the state's utilities, referred to as Transmission Providers in CCPG, must file a ten-year transmission plan and supporting documentation along with 20-year conceptual long-range scenarios. In accordance with Rule 3627, the CCPG Transmission Providers (Black Hills Energy, Tri-State Generation and Transmission Association, Inc. ("Tri-State"), and Public Service; together, the ("Joint Utilities") filed their coordinated 10-year transmission plan for the State of Colorado in Proceeding 20M-0008E on February 3, 2020.[1] As the plan details, transmission planning is a highly collaborative process that includes significant coordination between Transmission Providers as well as interested stakeholders. In addition, CCPG has a working group that evaluates 20-year conceptual transmission scenarios through regular meetings in an open stakeholder process as required by Rule 3627, which Public Service also filed on February 3, 2020 in Proceeding No. 20M-0008E.

By Decision No. C20-0213-I, the Commission directed the Joint Utilities to supplement their original filings and submit additional information on a series of questions. Consistent with that directive, the Joint Utilities filed a Supplemental Report on June 8, 2020. By Decision No. R20-0608-I, the Administrative Law

[1] 10-Year Transmission Plan and 20-Year Conceptual Scenario Report for the State of Colorado.

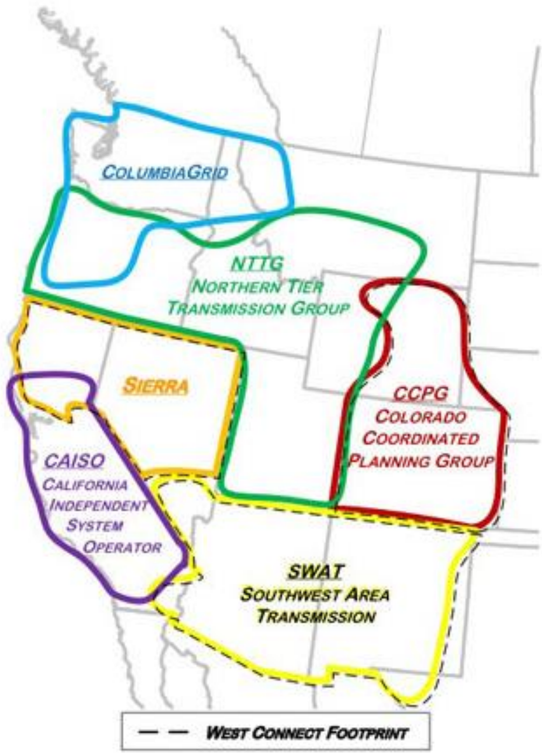
Judge ("ALJ") assigned to the proceeding asked for further additional information from the Joint Utilities, which they filed on September 18, 2020. This information is publicly available through the Commission's e-filing system, with the 10-year plan and 20-year scenarios.[2] I have also attached the 2020 Amended Ten-Year Transmission Report and Supplemental Report (filed in Proceeding No. 20M-0008E) as Attachment HS-2 to my Direct Testimony.

Q. HOW DOES CCPG INTEGRATE WITH OTHER JOINT PLANNING FORUMS?

A. The CCPG is one of three sub-regional planning groups that comprise WestConnect, which is a regional planning forum within the Western Electricity Coordinating Council ("WECC"), the Electric Reliability Organization ("ERO") delegate for the Western Interconnection. WestConnect includes CCPG plus two other sub-regional planning groups: the Southwest Area Transmission Group and the Sierra Subregional Planning Group. Figure HS-D-1 below shows the regional and sub-regional planning groups within WECC.

[2] http://www.transmission.xcelenergy.com/Planning/Planning-for-Public-Service-Company-of-Colorado/Colorado-Public-Utilities-Commission-Rule-3627

Figure HS-D-1: Regional and Sub-regional Planning Groups within WECC



Q. HOW HAS THE CCPG PROCESS EVOLVED TO ADDRESS TRANSMISSION PLANNING ISSUES IN LIGHT OF THE STATE'S AND UTILITIES' VARIOUS CARBON EMISSION REDUCTION OBJECTIVES?

A. As the state and utilities have pursued increasingly progressive carbon emission reduction objectives, the CCPG has adapted to facilitate coordination and collaboration between interested stakeholders and transmission providers. Most notably, this has occurred through a variety of "task force" sub-groups who collaboratively evaluate and study potential transmission solutions to emerging policy and technical issues. For instance, CCPG created the Rush Creek Task Force, the Lamar-Front Range Task Force (which identified a project that formed a basis of the Pathway Project), the 80X30 Task Force, and the Colorado Energy Plan Task Force. CCPG also has a variety of working groups and subcommittees that study new and emerging issues, such as the Energy Storage, Conceptual Planning, and Voltage Coordination working groups. Additional information is available through the CCPG website[3].

[3] http://regplanning.westconnect.com/ccpg.htm

III. PUBLIC SERVICE'S TRANSMISSION PLANNING EFFORTS LEADING TO THIS PROCEEDING AND THE PATHWAY PROJECT

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 transmission planning efforts that led up to this 2021 ERP & CEP filing. I also describe the interrelationship of the 2021 ERP & CEP with the Pathway Project for which the Company filed an Application for a CPCN on March 2, 2021 in Proceeding No. 21A-0096E, and how the Pathway Project will benefit the Phase II competitive solicitation that occurs in this proceeding.

Q. PLEASE SUMMARIZE THE COMPANY'S TRANSMISSION PLANNING EFFORTS THAT LED UP TO THIS FILING.

A. As Ms. Trammell explains, following the Company's 2016 ERP, Public Service's Transmission Planning and Resource Planning groups have been actively collaborating on how to better align their respective processes for future ERPs. One of the outcomes of those efforts has been attempting earlier identification of the anticipated size and location of potential generation resources needed to meet public policy initiatives, so that Public Service's transmission planners can help identify the transmission necessary to reliably accommodate new resources. As a result, the Transmission Planning and Resource Planning teams work in close coordination to achieve the same objective of figuring out how to recalibrate the state's grid to reliably and cost-effectively meet the state's emission reduction goals. Another effort has been to further leverage the expertise of the CCPG and its various Task Forces, subcommittees, and workgroups to identify mutuallybeneficial solutions where multiple transmission providers are attempting to accomplish similar resource planning and policy goals. On the technical side, the Company's Transmission Planning department has a team of committed technical experts who have been working, and will continue to work, diligently to study and assess a multitude of resource planning scenarios. The most notable and tangible outcome of those efforts is the Pathway Project, a 560-mile double circuit, networked transmission facility that Public Service filed a CPCN for on March 2, 2021.

Q. PLEASE PROVIDE AN OVERVIEW OF THE PATHWAY PROJECT.

A. The Pathway Project will consist of approximately 560 miles (which amounts to 1,120 circuit-miles) of new, double-circuit 345 kV transmission line, the expansion of three existing substations (Fort St. Vrain, Pawnee, and Harvest Mile), the expansion of one planned but not yet in-service substation (Tundra), and construction of three new substations (Canal Crossing, Goose Creek, and May Valley).[4] The Pathway 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 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

[4] The three new substations will be 345 kV switching stations. 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).

Fort St. Vrain generating station) in Platteville in western Weld County. The Pathway Project will then span east to a new substation near Pawnee, east/southeast to near the Cheyenne Ridge Wind Project, south to near Lamar, and then west to the Tundra Substation, near the Comanche generating plant. The Pathway Project will then run north to the Company's existing Harvest Mile Substation, located adjacent to the City of Aurora in Arapahoe County. A vicinity map of the Pathway Project and the five Project segments is provided as Attachment HS-3.

Q. DID THE COMPANY PRESENT ANY ADDITIONAL TRANSMISSION PROJECTS FOR COMMISSION CONSIDERATION IN ITS PATHWAY PROJECT CPCN?

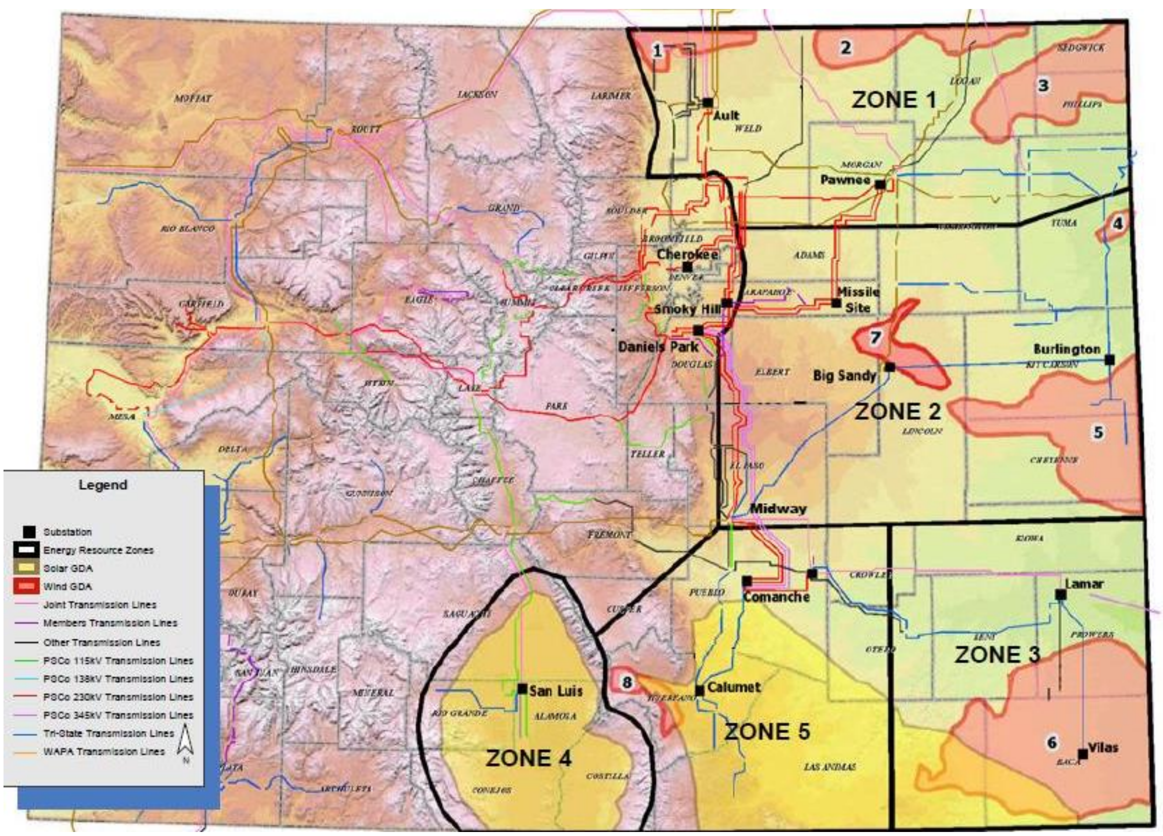
A. Yes. Public Service also presented for Commission consideration a 90-mile, 345 kV transmission extension called the May Valley-Longhorn Extension. The May Valley-Longhorn Extension would run from the southeastern corner of the Pathway Project, near Lamar, Colorado and extend south to near Vilas, Colorado providing developers with transmission access to wind-rich areas in the southeastern area of the state. A vicinity map of the May Valley-Longhorn Extension is provided as Attachment HS-4.

Q. PLEASE SUMMARIZE THE TECHNICAL BENEFITS OF THE PATHWAY PROJECT IN RELATION TO THE 2021 ERP & CEP.

A. The Pathway Project would provide generation resource bidders with a networked, backbone transmission resource in a large portion of the state that currently lacks such transmission capacity. Importantly, the Pathway Project's looped configuration and geographic scope provide interconnection points for clean energy resources located in four of the five Energy Resource Zones ("ERZ") designated pursuant to Senate Bill 07-100 ("SB 07-100").

Figure HS-D-2 below shows the ERZs in Colorado in relation to existing transmission.

Figure HS-D-2: Energy Resource Zones



As Figure HS-D-2 shows, there is very limited transmission available in the eastern portion of Colorado. In fact, there is virtually no transmission capacity in this part of the state. Because there is not enough existing transmission infrastructure in the eastern portion of the state to reliably accommodate the level of generation needed to achieve the state's clean energy objectives, absent a new major, strategic transmission resource in eastern Colorado, generators would be left to develop, on an ad-hoc and uncoordinated basis, long radial lines or generation tie lines (referred to as "gen-ties") to interconnect dispersed clean energy resources to the Company's existing transmission network. This approach has numerous drawbacks from a transmission planning and operations perspective and should be avoided. Moreover, requiring individual bidders/generators to construct radial lines or gen-ties on an uncoordinated basis to interconnect to the Company's system would add potentially significant costs to projects. The Pathway Project, however, will effectuate an interconnected transmission system that: (1) achieves improved reliability and operational flexibility while interconnecting needed clean generation resources; and (2) enables the delivery of electric energy from these generation resources to the Company's load centers.

An additional benefit of the Pathway Project is that it will network a large portion of the existing, Rush Creek and Cheyenne Ridge 345 kV transmission line(s) that together effectively comprise a 153-mile radial generator tie-line currently connected to Public Service's networked transmission system only at Missile Site Substation.

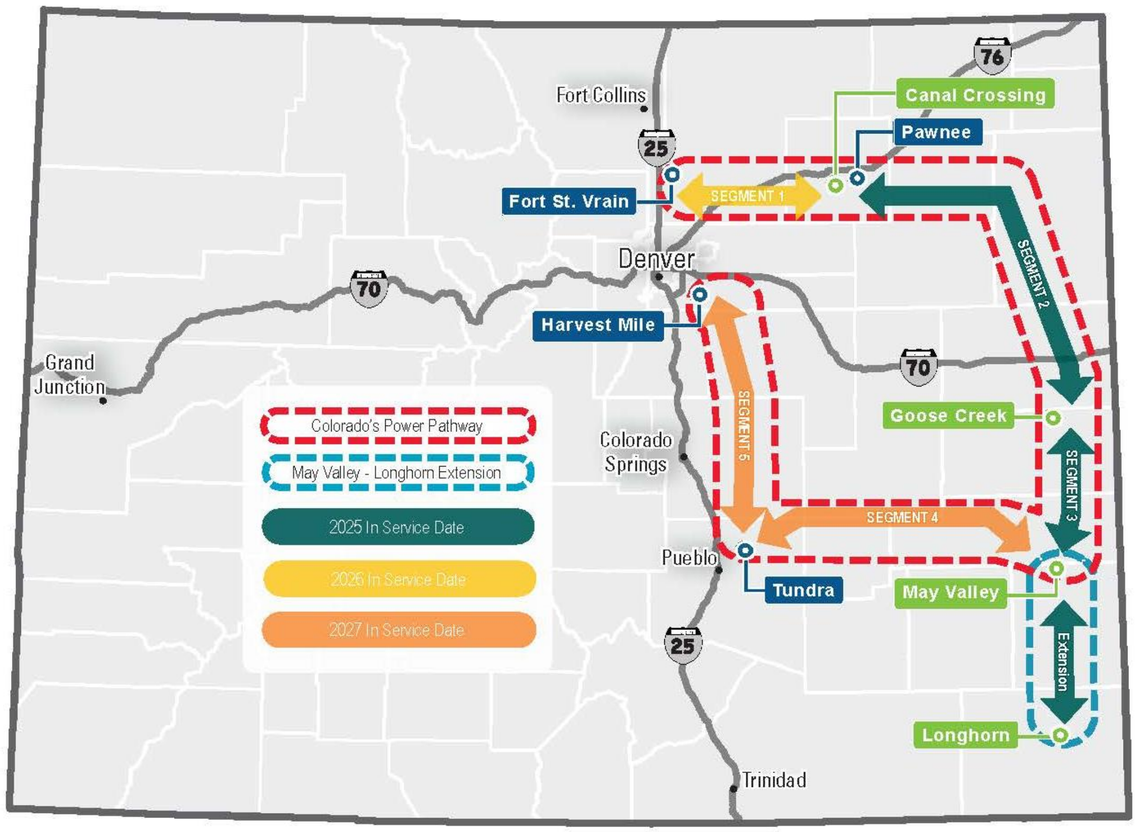
On the whole, the Pathway Project is a networked, backbone transmission resource that will meet the system performance requirements specified in all applicable North American Electric Reliability Corporation ("NERC") reliability standards, thereby providing the Company with greater operational and reliability benefits for its Transmission Operator, Transmission Planner and Balancing

Authority footprints, than if generators were left to propose long, dispersed, and uncoordinated generation tie-lines to interconnect to Public Service's system.

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

A. The Company plans to construct the Pathway Project in three major phases. This sequencing will enable portions of the Project to be in-service before the entire Project is completed. Segments 2 and 3, including the Pawnee Substation expansion and the new Canal Crossing, Goose Creek, and May Valley Substations, will be constructed first and in service by the end of year 2025. In addition, if the May Valley-Longhorn Extension is approved, the planned in-service date for these facilities is end of year 2025. The in-service date for Segment 1 including the Fort St. Vrain Substation expansion is end of year 2026. The Company anticipates completing the remaining segments, Segments 4 and 5 (including the Tundra and Harvest Mile Substation expansions), by the end of 2027. Figure HS-D-3 below depicts the Company's planned sequencing for the Project.

Figure HS-D-3: Pathway Project Sequencing Map



Q. HOW DOES THE SEQUENCING AFFECT POTENTIAL GENERATION INTERCONNECTIONS?

A. Segments 2 and 3 (new Canal Crossing to Goose Creek, and Goose Creek to May Valley) will traverse the wind-rich areas in eastern Colorado. By having those segments and substations constructed and in-service by the end of 2025, wind and solar developers will be able to interconnect their resources prior to the expiration of the Production Tax Credits ("PTCs") and Investment Tax Credits ("ITCs"). Bids submitted by generation developers will enable significant cost savings to customers if those generating resources can be online before the end of 2025, which is when the PTC is set to expire and the ITC steps down. Thus, Public Service anticipates that placing Segments 2 and 3 and the May Valley-Longhorn Extension (if approved) in service by the end of 2025 could drive clean energy cost savings for customers. As Company witnesses Ms. Alice K. Jackson and Mr. Jack W. Ihle explain, adding new clean generation by the end of 2025 supports the state's greenhouse gas emissions reduction target timelines. The construction of the first phase of the Project will network the existing Rush Creek and Cheyenne Ridge Gen-Tie line(s), thereby providing improved reliability for the interconnected 1,400 MW of wind generation plus other system operation benefits. The Company will next construct Segment 1, which it anticipates placing in service by 2026, followed by Segments 4 and 5, which it anticipates placing in service by the end of 2027. These segments will provide improved reliability on the new Pathway Project backbone transmission system and ensure that electric energy generated by the new renewable generation facilities will be delivered to the Company's load centers.

Q. PLEASE SUMMARIZE THE TECHNICAL BENEFITS OF THE MAY VALLEY-LONGHORN EXTENSION IN RELATION TO THE 2021 ERP & CEP.

A. This optional extension to the Pathway Project would establish additional transmission interconnection opportunities for potential clean energy resource developers in the wind-rich southeastern area of the state. Having a well-planned double circuit transmission line in this area will not only facilitate clean energy resource development but will also minimize the potential likelihood of clean energy project developers needing to construct multiple gen-tie lines in this region to interconnect to the Pathway Project 345 kV transmission backbone.

Q. HAS THE COMPANY IDENTIFIED SPECIFIC GENERATION FACILITIES THAT WILL INTERCONNECT TO THE PATHWAY PROJECT?

A. No. Generation facilities that will ultimately interconnect to the Pathway Project will largely be driven by the competitive Phase II resource solicitation that will occur in this Proceeding. However, the proposed location and route of the line is strongly influenced by the location of developer bids received in previous ERPs.

Q. HOW HAS THE COMPANY EVALUATED THE GENERATION AND TRANSMISSION RESOURCES THAT WILL BE NEEDED TO ACHIEVE AN 80 PERCENT CARBON REDUCTION BY 2030?

A. As explained by Company witnesses Ms. Jackson and Mr. James F. Hill, the State's 2030 clean energy objectives will result in the need for accelerated retirements of coal-fired generating units and the continued addition of zero-emission variable energy resources over the coming years. Mr. Hill explains in his Direct Testimony that the Company's Preferred Plan in this 2021 ERP & CEP forecasts the need to acquire approximately 3,900 MW (nameplate) of utility-scale wind and solar resources, not including distributed energy resources, storage, and additional dispatchable resources. These generating resources will require access to the transmission system in order to provide electricity to the Company's major load centers along the Front Range. While we cannot know with certainty the full package of additional transmission resources that will be needed to support the resource portfolio approved in this proceeding, we do know that the existing transmission network, especially in eastern Colorado, is not capable of integrating the magnitude of new resources needed to implement the Company's 2021 ERP & CEP.

Q. IS THE COMPANY PROPOSING THE PATHWAY PROJECT FOR THE 2021 ERP EXACTLY AS ENVISIONED BY THE JOINT TRANSMISSION PROPOSAL SUBMITTED IN PROCEEDING NO. 19R-0096E?

A. No. As Ms. Trammell explains in her Direct Testimony, while the Pathway Project was proposed consistent with the spirit that gave rise to the Joint Transmission Proposal and will be available for bidders to interconnect to in the Company's Phase II resource solicitation in this Proceeding, it does not technically meet the definition of a "bid-eligible transmission project" as proposed there. The Pathway Project cannot wait or else it will not be able to deliver the benefits it can otherwise provide to the State of Colorado through the realization of backbone transmission investment in advance of transformative renewable resource generation additions.

Q. IS PUBLIC SERVICE PROPOSING ANY OTHER PROJECTS IDENTIFIED IN ITS MOST RECENT RULE 3627 REPORT AS "BID ELIGIBLE PLANNED TRANSMISSION PROJECTS"?

A. No, not at this time. In Public Service's Ten-Year Transmission Plan filed in the most recent Rule 3627 filing, we identified a number of other conceptual transmission projects related to SB 07-100 and the Company's Clean Energy Plan Goals.[5] I say "other conceptual transmission projects" because the Lamar-Front Range Transmission Project is the project that formed the basis of the Pathway

[5] 10-Year Report, at pp. 65-72, Proceeding No. 20M-0008E.

Project, and which the Company has identified in multiple Rule 3627 filings, including its most recent filing. At the time of the filing its 2020 Rule 3627 Ten-Year Transmission Plan, the Lamar-Front Range Transmission Project was listed as a conceptual project.

Public Service does not believe the remaining conceptual projects are reasonable to designate as bid eligible including: the Weld-Rosedale-Box Elder-Ennis Project; the Weld County Transmission Project; and the San Luis Valley Project.

Public Service is not proposing that the Weld-Rosedale-Box Elder-Ennis Project be considered a bid eligible planned transmission project at this time because this project is intended to enhance load serving capability by providing local reliability improvements in the Southern Greeley area. It is not to increase injection capability for purposes of interconnecting new generation. Any resulting injection capability increase would be incidental since, in general, any transmission improvement has the potential to positively impact the local area injection capability.

Similarly, Public Service is not proposing that the Weld County Transmission Project be considered a bid eligible planned transmission project at this time because the project planning is in its infancy. Accordingly, the project's need, benefits and tentative scope have not been established yet. Depending on how the project development progresses—whether as additional transmission that dovetails with the planned and conceptual load-serving projects in the Greeley area, or as completely new transmission intended to enhance transfer capability from Ault to Fort St. Vrain—the resulting project may (or may not) assist Public Service in meeting its emission reduction goals.

Q. WHY ISN'T THE COMPANY PROPOSING TO DESIGNATE THE SAN LUIS VALLEY-PONCHA 230 KV PROJECT IDENTIFIED IN ITS 3627 REPORT AS A BID-ELIGIBLE PLANNED TRANSMISSION PROJECT?

A. The San Luis Valley-Poncha 230 kV Transmission Project ("San Luis Valley Project") was originally conceived as a joint Public Service and Tri-State project for mutual reliability needs and interest exporting generation from ERZ 4, which is the San Luis Valley. Tri-State has recently indicated that Tri-State no longer identifies the San Luis Valley Project as planned, but rather, Tri-State is "suspending" this project and will be re-evaluating the project through the CCPG.[6] From Public Service's perspective, there are currently several significant impediments and risks to developing the San Luis Valley Project, such as constructability concerns given the significant routing challenges which include traversing a wildlife refuge, obtaining the necessary permitting and land rights from a mix of public and private entities, the fact that the project would traverse the Company's Wildfire Risk Zone, and the rugged, mountainous terrain that presents potentially hostile weather conditions as well. Second, the Company has not identified a sufficient cost to benefit ratio. Given the high construction and siting and land rights costs, along with the projected 500 MW of injection capability

[6] Tri-State Significant Transmission Project Status, March 18, 2021. https://doc.westconnect.com/Documents.aspx?NID=19308

(compared to roughly $500 million in investment), this project presents too many challenges to be currently designated a bid-eligible project at this time. That said, CCPG maintains a San Luis Valley Task Force, of which Public Service is a member, and we will continue to assess feasibility of the project and potential alternatives.

IV. TRANSMISSION PLANNING STUDIES AND SYSTEM RELIABILITY

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

A. In this section of my Direct Testimony, I discuss the various transmission studies and evaluations that have been, or will be, performed to ensure the ongoing reliability and resiliency of Public Service's transmission system in conjunction with the Company's 2021 ERP & CEP. Specifically, I discuss the transmission reliability review process that has occurred and will continue to occur to support the 2021 ERP & CEP. This includes: (1) the studies that have been performed to evaluate impacts to the transmission system from the proposed coal-fired generation unit retirements and fuel conversion at existing generating facilities, the study results finding these retirements are not expected to have unacceptable reliability impacts, and the additional studies and evaluations that the Company intends to undertake; and (2) how the Company's must-run designations may be influenced or impacted by the portfolio approved as part of this 2021 ERP & CEP.

A. Transmission Planning & Generator Retirements/Fuel Conversion

Q. PLEASE SUMMARIZE THE TRANSMISSION RELIABILITY REVIEW AND PLANNING PROCESS THAT HAS OCCURRED TO SUPPORT THE 2021 ERP & CEP.

A. I would first preface this discussion by noting that transmission reliability review and planning is not a static activity that occurs at a single point in time during the resource planning process. Rather, evaluating and planning for transmission reliability is an iterative, ongoing, and continual process that occurs before, during, and after the long-term ERP regulatory process. The Company has conducted and, as I discuss below, will continue to conduct rigorous transmission reliability assessment studies to support its 2021 ERP & CEP, particularly as it develops its proposed portfolio as part of the Phase II process, and then transitions to implementing the approved portfolio. As Company witness Mr. Hill noted, the Company's transmission reliability review and planning process to support this 2021 ERP & CEP filing involved an assessment of the Company's resource planning projections. This assessment was performed to determine if the planned transmission system expansion (i.e., the Pathway Project) could reliably deliver 3,000 MW coincident injection or output to customer load from the approximately 3,900 MW (nameplate) of utility-scale wind and solar resources within the Company's resource acquisition target to meet the 2030 emission reduction goals.

Q. IS THE COMPANY PROPOSING ANY GENERATOR RETIREMENTS OR FUEL CONVERSION AS PART OF ITS PROPOSED 2021 ERP & CEP?

A. Yes, as discussed by Ms. Jackson and Mr. Hill, the 2021 ERP & CEP consists of proposed coal actions, which comprise the following: (1) accelerated retirement of Hayden Generating Station (Unit 2 in 2027, and Unit 1 in 2028); (2) retirement of Craig Unit 2 in 2028; (3) conversion of Pawnee Generating Station from coal to gas operation; and (4) reduced operation of Comanche 3 coal unit starting in 2030 followed by retirement in 2040.

Q. WILL THESE PROPOSED GENERATION FLEET CHANGES HAVE AN ADVERSE IMPACT ON TRANSMISSION SYSTEM RELIABILITY?

A. Preliminary studies have not identified any unacceptable adverse system impacts due to the generation changes resulting from proposed coal-fired generation retirements, fuel conversion, and reduced operation. However, below, I discuss the identified and/or anticipated system impacts for each of these generation changes and potential mitigation plans to accommodate such.

Q. HAS THE COMPANY EVALUATED TRANSMISSION SYSTEM PERFORMANCE IMPACTS DUE TO RETIREMENTS OF HAYDEN AND CRAIG COAL GENERATING PLANTS LOCATED IN THE WESTERN SLOPE?

A. Yes. Preliminary studies performed by Public Service to assess the Western Slope transmission system performance due to the retirements of all five units (Hayden 1 and 2, and Craig 1, 2, and 3)[7] comprising the Hayden and Craig coal generation plants have not identified any adverse reliability impacts that would suggest the need for mitigation or transmission reinforcement.

Q. PLEASE ELABORATE ON WHY THE RETIREMENT OF FIVE LARGE GENERATING UNITS WILL NOT RESULT IN ANY ADVERSE IMPACT ON TRANSMISSION SYSTEM RELIABILITY.

A. Although this outcome may seem counter-intuitive, it has a reasonably plausible explanation. Essentially, it has to do with the relatively small amount of aggregate load served by the Western Slope transmission system. Although the aggregate rated output of the five generating units in Craig and Hayden plants is approximately 1,900 MW, the aggregate Western Slope peak load served from this generation is approximately 1,500 MW. Consequently, the 1,900 MW injection lost due to generation retirements results in a need to import 1,500 MW into the

[7] Tri-State previously announced that Craig 1 unit will close by the end of 2025 and Craig 3 unit will close by the end of 2030.

Western Slope area, which is well within the transfer capability of the extensive existing 345 kV and 230 kV transmission lines comprising the Western Slope transmission system (please see Attachment HS-1). And since many of these transmission lines see reduced loading and thus lesser reactive losses, the system voltages stay within acceptable range despite the loss of reactive power from generators—that is, the Western Slope system voltages do not change significantly due to the generation retirements. These preliminary study outcomes will be vetted by a collaborative study to be performed by the Western Slope Subcommittee.

Q. WHAT IS THE WESTERN SLOPE SUBCOMMITTEE?

A. The Western Slope Subcommittee is a CCPG Subcommittee established to study the existing western Colorado transmission system and identify deficiencies that can be improved through transmission projects. Public Service participates in the Western Slope Subcommittee along with Tri-State, Platte River Power Authority ("PRPA"), and Western Area Power Administration-Rocky Mountain Region ("WAPA-RMR") – the Colorado entities that own and operate the transmission facilities comprising the Western Slope interconnected transmission system.

Q. DOES THE COMPANY INTEND TO FOLLOW-UP ITS PRELIMINARY WESTERN SLOPE STUDY WITH ADDITIONAL STUDIES?

A. Yes, Public Service will perform additional studies, both individually and collaboratively, to evaluate and address any findings that may not have been identified by the preliminary studies. This will include performing short circuit analysis for the Western Slope transmission system to assess the system strength reduction due to planned generation retirements. The CCPG Western Slope Subcommittee kicked off a collaborative study effort in September 2020 to evaluate the transmission system performance impacts due to planned Hayden and Craig generation retirements. The final study report of the Western Slope Subcommittee will represent the consensus solutions identified to address any adverse system reliability impacts due to the Hayden and Craig generation retirements. While the final study report is a collaborative effort and Public Service cannot dictate when the report will be finalized, we estimate the final study report may be completed by fall 2021.

Q. HAS THE COMPANY EVALUATED THE TRANSMISSION SYSTEM PERFORMANCE IMPACTS DUE TO THE CONVERSION OF PAWNEE FROM COAL TO GAS?

A. No, we do not believe that an evaluation is needed as this conversion will not materially impact system reliability. Changing the fuel source from coal to gas will not change the generating unit's rated MW output or significantly alter its dynamic behavior, and therefore its impact on the transmission system will not change.

Q. HAS THE COMPANY STUDIED TRANSMISSION SYSTEM PERFORMANCE IMPACTS DUE TO THE REDUCED OPERATION OF COMANCHE 3?

A. While Public Service has begun to study this issue, it is still determining the full range of comprehensive studies required to assess the transmission system impacts associated with the proposed reduced operation of Comanche 3 beginning in 2030.

Q. WHAT STUDIES ARE NECESSARY FOR THE COMPANY TO EVALUATE THE SYSTEM RELIABILITY IMPACTS DUE TO THE PROPOSED REDUCED OPERATIONS OF COMANCHE 3?

A. In addition to the typical transmission studies that evaluate the steady-state and dynamic performance of the transmission system based on power flow and stability analysis respectively, two additional types of studies will be needed to ensure all potential impacts are identified. One is the short-circuit analysis needed to determine the significant reduction in grid strength expected when no synchronous generators are available at Comanche after the retirement of Comanche Units 1 and 2, and with Comanche Unit 3 off-line (due to reduced operation or retirement). This is to evaluate if the Comanche location on the transmission system will become unacceptably "weak" due to the lack of synchronous generation on the system after the planned coal generation retirements, and thus determine the potential need for grid strength reinforcement at Comanche.[8] The other analysis required is the voltage flicker level evaluation due to the proximity of EVRAZ steel mill load to Comanche, which helps determine the potential need for voltage flicker mitigation. Further, since both voltage flicker and the stability performance of inverter-based resources ("IBR") is adversely impacted by weak grid condition, the flicker analysis and stability analysis outcomes are both impacted by the short

[8] Grid strength is higher closer to generating stations since traditional generators (i.e., synchronous machines) produce significant amounts of short-circuit current. This is because system strength (or stiffness) at any location is directly proportional to the magnitude of available short-circuit current; hence, why the metric used for system strength is called Short Circuit Ratio ("SCR"). System strength decreases as distance from a generating station increases.

circuit analysis results. Together these analyses comprise a comprehensive evaluation to determine the need for devices such as synchronous condensers and/or static compensators ("StatComs") for grid strength reinforcement and voltage flicker mitigation respectively.

Q. OF THESE ANALYSES, WHICH HAVE PUBLIC SERVICE BEEN ABLE TO PERFORM AT THIS POINT IN TIME?

A. Public Service has performed both steady state analysis and voltage flicker studies. Public Service has evaluated the steady state performance of the Comanche area transmission system and did not find any thermal violations (i.e. overloads) or voltage limit violations needing mitigation. Also, Public Service has previously completed the EVRAZ voltage flicker study in 2018 as part of the voltage control studies for implementing the Colorado Energy Plan Portfolio ("CEPP"). Since the voltage flicker study was performed by modeling the Comanche 1 and 2 retirements and with Comanche 3 off-line, its results and recommendations are also valid for the reduced operation or retirement of Comanche 3. So, no additional voltage flicker study is needed to verify and validate the need to install a 95 Megavolt-Ampere Reactive ("Mvar") StatCom at EVRAZ to control the voltage flicker to within an acceptable level.

Q. WHEN WILL PUBLIC SERVICE PERFORM THE SHORT CIRCUIT AND STABILITY PERFORMANCE ANALYSES TO DETERMINE IF ANY ADDITIONAL MITIGATION IS NEEDED TO ENABLE COMANCHE 3 RETIREMENT?

A. The Company performed preliminary short circuit analyses, which have identified the approximate reduction in grid strength that will occur at Comanche when all three synchronous generators are no longer online or available. However, the potential impact of reduced grid strength on stability performance of the new inverter-based resources in the Comanche area cannot be evaluated with confidence until the more accurate dynamic models for the as-built PV solar generation resources acquired in the CEPP become available. Besides the PV solar generators interconnecting at Comanche, this includes PV solar generators interconnecting at the Company's Midway, Mirasol, Tundra and Boone substations that are in close electrical proximity to Comanche. Future stability analyses will also need to evaluate whether undesirable control interactions between the EVRAZ Statcom and the PV solar plant controllers, which may increase with reduced grid strength, would occur and need to be mitigated. As noted earlier, these stability analyses require the availability of accurate dynamic models for generation resources, which would typically become available close to their in-service date.

Q. WHAT ARE THE TYPICAL SOLUTIONS ADOPTED FOR MITIGATING UNACCEPTABLE DYNAMIC PERFORMANCE OF INVERTER BASED RESOURCES OCCURRING DUE TO WEAK GRID STRENGTH?

A. Unacceptable dynamic performance of IBR typically manifests itself as undesirable control interactions between their plant controllers. Typically, the first mitigation option employed is controller tuning – that is, adjusting the controller's settings such as its gains and time constants – which is most often sufficient to eliminate the interactions and thus achieve dynamic stability. This minimum cost "software" based mitigation tends to become increasingly less effective as the grid strength reduces below a certain threshold. While there is no bright-line metric for such threshold, it is generally accepted that when the Short Circuit Ratio ("SCR") at any grid location is less than 2.0–3.0, it is considered weak and the dynamic stability of IBRs becomes increasingly marginal, moving towards unacceptable. Therefore, the only effective mitigation at some weak grid strength locations is to increase the SCR and make it stronger – this is typically achieved by installing synchronous condensers. At an existing generating plant like Comanche, this may be achieved by conversion of a retiring generator. Therefore, the unavailability of Comanche 3 may, at best, require the minimal cost mitigation of tuning the IBR plant controllers and, at worst, require conversion of Comanche Unit 1 or Unit 2 to a synchronous condenser. Future detailed short-circuit and stability analyses that consider not just Public Service's Comanche generator retirements but also account for all the proximate generator retirements (by Colorado Springs Utilities, Black Hills Energy and/or WAPA-RMR) will determine what mitigation is adequate. Public Service intends to complete these analyses in 2024-2025 to enable an evaluation and determination of the need to convert Comanche 2 to a synchronous condenser prior to its scheduled retirement at the end of 2025.

Q. YOU MENTIONED THE IMPORTANCE OF STUDYING ALL PROPOSED COAL GENERATOR RETIREMENTS TO DETERMINE THEIR CUMULATIVE IMPACT ON GRID STRENGTH AND DYNAMIC STABILITY OF IBRS. IS THERE ANY OTHER ADVERSE SYSTEM IMPACT THAT COULD OCCUR DUE TO THE AGGREGATE PROPOSED COAL GENERATOR RETIREMENTS IN COLORADO?

A. Yes. The cumulative inertia loss due to the unavailability of rotating masses inherent to synchronous machines (resulting from the proposed coal generator retirements) adversely impacts the transmission system's frequency recovery performance after a disturbance. NERC Standards specify the primary and secondary frequency response performance metrics that must be met, such as ROCOF ("Rate of Change Of Frequency"), Frequency Nadir, DCS ("Disturbance Control Standard"), etc. The cumulative erosion of inertia due to the planned coal-fired generator retirements may result in deficient frequency performance which could, during certain operating conditions, degenerate into frequency instability. In the more distant future when the resource acquisitions from this 2021 ERP & CEP ultimately are coming online, Public Service intends to perform screening studies to predictively evaluate the rate of decline in frequency performance. Potential mitigation to arrest unacceptable frequency performance decline would consist of requiring future IBRs (whether wind, solar, battery or hybrid plants) interconnecting to the Public Service system to be capable of providing "synthetic" inertia to compensate for the loss of (real) inertia from retiring synchronous generators. Recognizing that the frequency response capability available from technology advancements of future IBRs cannot be ascertained at this time, the Company will continue to monitor this issue but considers it premature to study the need for and/or identify optimal mitigation solutions until technical specifications of the resource acquisitions from this 2021 ERP & CEP become known.

B. Transmission Reliability & Must Run Designations

Q. COMPANY WITNESS MR. JOHN T. WELCH STATED THAT MUST-RUN DESIGNATION(S) IS ONE TOOL USED FOR PURPOSES OF SAFE AND RELIABLE TRANSMISSION SYSTEM OPERATION. IS THIS ACCURATE?

A. Yes. As Company witness Mr. Welch explains in his Direct Testimony, must-run designation(s) is a tool used when the transmission system cannot deliver the full renewable generation output due to a transmission constraint or event.

Q. WHAT IS A MUST-RUN DESIGNATION?

A. Staff of the Federal Energy Regulatory Commission ("FERC") has a good explanation in its Energy Primer:

> Reliability must-run ("RMR") units are generating plants that would otherwise retire but the RTO/ISO has determined they are needed to ensure reliability. They can also be units that have market power due to their location on the grid. RTO/ISOs enter into cost-based contracts with these generating units and allocate the cost of the contract to transmission customers. In return for these payments to the generator, the RTO/ISO may call on the owner of an RMR generating unit to run the unit for grid reliability.

> The payment must be sufficient to pay for the cost of owning and maintaining the unit, even if it does not operate.[9]

Q. ARE MUST-RUN DESIGNATIONS A COMMON INDUSTRY PRACTICE?

A. Yes. Must-run designations are a system operations tool that assists in the safe and reliable delivery of power. Must-run designations or contracts are not an uncommon industry practice and the Company's use of must-run designations is consistent with general industry practice across jurisdictions and regulatory market structures. In fact, the designation of must-run generation is prevalent in regions with organized markets administered by a Regional Transmission Organization ("RTO") or independent system operator ("ISO"), as well as in jurisdictions with traditionally regulated utility structures across the country. The use of some type of RMR contract/agreement is a prevalent practice in nearly every existing RTO or ISO (i.e., California ISO, Electric Reliability Council of Texas, Midwest ISO, Southwest Power Pool, PJM, ISO-New England, New York ISO). Further, fully regulated utilities like Public Service also use must-run designations as a tool to maintain system reliability, and thus the Company's use of must-run designations is certainly not an outlier.

Q. WHAT KIND OF MUST-RUN CONSTRUCT DOES THE COMPANY USE, AND FOR WHAT PURPOSE?

A. Although the need for must-run generation is primarily determined by transmission system reliability in every construct, the RMR contracts in the RTO/ISO construct

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[9] Energy Primer: A Handbook of Energy Market Basics, at 66 (Apr. 2020), https://www.ferc.gov/sites/default/files/2020-06/energy-primer-2020.pdf.

are invariably for ensuring continued availability of generating units that would otherwise be retired. On the contrary, the must-run designation construct used by Public Service is not to prevent or delay a generating unit retirement – it is essentially a proactive system adjustment implemented to mitigate the potential system operating limit exceedance(s) likely to occur due to the juxtaposition of one or more transmission events. Such events have typically (and increasingly) consisted of periods of high level of renewable generation output coupled with scheduled critical transmission outage(s), which creates transmission constraints not seen during system intact conditions. Clearly, the Company uses must-run designation as an operating tool to maintain reliable system operation by mitigating transmission congestion. Unlike the RTO/ISO construct where must-run costs are based on a long duration RMR contract regardless of the unit's actual operation, the Public Service construct utilizes must-run generation on as-needed basis such that associated must-run costs are accrued based on actual generation output. Further, the net transmission congestion relief cost is even lower since the must-run generation cost would be offset by the avoided cost of renewable generation curtailment. As is also explained by Mr. Welch, curtailment and must-run designation are two operating tools essential to integrate large and increasing levels of renewable generation.

Q. WHAT IS THE RELEVANCE OF MUST-RUN DESIGNATIONS TO THE 2021 ERP & CEP FROM A TRANSMISSION PLANNING PERSPECTIVE?

A. Although the Public Service construct uses must-run designations as a cost effective operating tool for maintaining reliable transmission operations, it is possible that relatively frequent and/or longer duration usage of must-run generation may indicate a chronic transmission congestion issue that merits exploring transmission improvement alternatives by Transmission Planning. In fact, Public Service has already committed to addressing such transmission reliability issues by providing a Must Run Solutions Analysis report to identify feasible alternative solutions to qualifying must-run designations (as per a recent decision I discuss below). However, with the significantly higher levels of variable energy-limited resources integrated into the Public Service system with the renewable generation procurement targets in the 2021 ERP & CEP, the reliance on operating tools of curtailment and must-run designation is expected to become increasingly prevalent.

Q. HOW WILL THE COMPANY'S MUST-RUN DESIGNATIONS BE INFLUENCED OR IMPACTED BY THE PORTFOLIO APPROVED AS PART OF THIS 2021 ERP & CEP, AND VICE-VERSA?

A. Although the Company intends to make significant transmission investments to accommodate the 2021 ERP & CEP preferred portfolio (the Pathway Project and the anticipated Denver metro-area transmission upgrades associated with it), the inherent variability of renewable generation coupled with scheduled transmission outages may nevertheless require continued usage of must-run designation as operating tool.

Q. ARE THERE ANY RECENT DECISIONS THAT ARE RELEVANT TO THIS DISCUSSION?

A. Yes. Questions surrounding the Company's must-run designations recently arose in the Company's recent Energy Commodity Adjustment ("ECA") prudence review filing, Proceeding No. 20A-0327E. In that proceeding, Staff and Public Service entered into a Settlement Agreement, subsequently approved by the Commission, that provided for future detailed reporting around must-run designations.

Q. WOULD MUST-RUN DESIGNATIONS CONTINUE IF PUBLIC SERVICE BECOMES PART OF AN RTO?

A. Must-run designations — whether ordered by the system operator or procured through an RMR contract/agreement (RTO or ISO) — are prevalent because the need for must-run generation dispatch is integral to "normal" system operation, especially with the increasing penetration of variable, non-dispatchable and energy-limited resources like wind and solar generation. Further, while certain planned transmission investments may reduce the need for must-run designations, the Company cannot eliminate the potential use of must-run designations if curtailment of non-dispatchable wind and solar generation is to be minimized, and as long as transmission outages for construction or maintenance must be scheduled. While must-run designations are commonly used in the utility industry, Public Service tries to minimize the use of must-run designations to the extent practicable. However, minimizing must-run usage comes at the expense of potentially increased reliance on curtailments – both cannot be minimized simultaneously. For these reasons, it appears unlikely that the use of must-run designations would discontinue if Public Service becomes part of an RTO. However, the existing Public Service construct for must-run designations may have to change and/or adapt for consistency with the prevalent practice(s) of the RTO.

V. PHASE II PROCESS AND OTHER TRANSMISSION-RELATED COST ESTIMATES

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

A. In this section of my Direct Testimony, I explain how the Company plans to develop and refine its transmission cost estimates for projects that relate to its ERP.

Q. YOU MENTIONED ABOVE THAT ADDITIONAL TRANSMISSION INVESTMENT BEYOND THAT CONTEMPLATED IN THE PATHWAY PROJECT CPCN FILING WILL BE NEEDED TO RELIABLY IMPLEMENT THE PORTFOLIO APPROVED AS PART OF PHASE II OF THIS PROCEEDING. PLEASE EXPLAIN.

A. Colorado's energy transition is not limited to generation resources and will likewise require a shift in how transmission planners have historically developed and analyzed transmission needs. As the 2016 ERP and CEPP demonstrated, facilities that offer grid support and reactive control, and that help mitigate congestion in or near load centers, have become and will become increasingly more critical to ensuring grid stability and reliability going forward. As Public Service looks to unlock new generation resources in more remote areas of the state, we expect additional transmission investments will be needed in the following categories: (1) Denver Metro area network upgrades; (2) grid (strength) reinforcement; (3) reactive/voltage support; and (4) generation interconnection facilities, which I discuss in turn below. As I explain below, estimates for these types of investments are not certain at this time because the location of the generation resources approved as part of the 2021 ERP & CEP will heavily influence and drive these costs.

Q. PLEASE DISCUSS THE ADDITIONAL TRANSMISSION STUDIES THAT WILL DRIVE THIS FUTURE INVESTMENT.

A. Determining transmission system reliability is an iterative process that consists of performing increasingly rigorous system performance assessment studies to determine and/or validate system reliability needs. This iterative process will result in better defined scope and specifications for the suite of transmission facilities needed to reliably operate the system. As the uncertainties affecting transmission planning study assumptions narrow with the availability of additional information, such as the known resource portfolio, the Company can correspondingly better identify its system reliability needs. And this is especially true for identifying and justifying the need for special-purpose equipment to maintain reliability, which requires specialized studies using highly precise system models that are typically available only at the latter stages of a project's development. Therefore, additional transmission studies will occur as part of this proceeding and after the Commission approves a portfolio in this proceeding to determine the full scope of transmission facilities and investment needed to implement the approved portfolio.

More specifically, as part of Phase II of this Proceeding, the Company will run additional power flow studies associated with the various portfolios evaluated during Phase II of the ERP. Given the short timeframe of the 120-day bid evaluation process, transmission studies will be performed to provide preliminary information about system reliability for purposes of portfolio comparison and to develop cost estimates for purposes of portfolio evaluation. After the Commission approves an ERP resource portfolio, the Company will then perform specialized and more granular performance assessment studies on a system-wide basis (e.g., reactive/voltage support studies, system stability studies, and short circuit studies), specific to the approved resource portfolio. These specialized studies have a two-fold purpose: (1) to review and refine the earlier transmission studies (performed for the ERP Phase II 120-Day Report process) based on generator locations, sizes, and technologies in the approved resource portfolio; and (2) to determine the reliability need for installing any special-purpose equipment such as synchronous condenser(s) and/or StatComs necessary to enable reliable system operation during a variety of generation dispatch and credible contingency scenarios.

Generator interconnection studies for future generation (including Company-owned generation) from this 2021 ERP & CEP will be performed in accordance with Xcel Energy's FERC-approved Open Access Transmission Tariff ("OATT"), through the Large Generator Interconnection Procedure ("LGIP").

A. <u>Denver Metro Area Network Upgrades</u>

Q. PLEASE EXPLAIN THE POTENTIAL ADDITIONAL INVESTMENT ASSOCIATED WITH THE DENVER METRO AREA UPGRADES.

A. We anticipate that additional transmission investment associated with the Denver Metro area network upgrades necessary to support 2021 ERP & CEP may be approximately $250 million. I would describe this cost estimate as a preliminary and illustrative cost estimate, which will be refined once a specific generation portfolio is approved as part of the ERP Phase II process. Given that the Company will not be able to specifically identify what network upgrades are needed to reliably implement the 2021 ERP & CEP until after a final portfolio is selected and approved, these future investments are not part of the Company's cost estimate for the Pathway Project. The potential need for several Denver Metro area network upgrades was identified based on overloads noted in Appendix B of the CCPG's 80x30 Task Force Report (Attachment HS-5). However, the specific engineering scope of network upgrades that will be needed to mitigate the overloads driven by the 2021 ERP & CEP will depend on the Company's approved resource portfolio. Additional power flow studies for the approved resource portfolio will confirm the anticipated overloads and required transmission capacity increases, which in turn will help determine the required network upgrades followed by cost estimates for the optimally engineered projects.

For example, regarding the transmission facilities needed to accommodate the 2016 ERP portfolio, an alternative better optimized transmission project (the Greenwood-Denver Terminal Project) was identified after the CEPP was approved and after additional studies were performed. As a result, the overload mitigation costs decreased from the 120-Day Report cost estimates.

B. Grid Strength Reinforcement

Q. YOU MENTIONED GRID STRENGTH REINFORCEMENT AMONG THE POTENTIAL ADDITIONAL INVESTMENTS. WHAT EXACTLY DOES THIS MEAN AND WHAT FACTORS WILL DRIVE THIS NEED?

A. Grid strength (also known as system strength) refers to the "stiffness" of transmission system—higher grid stiffness is desirable since it results in better system stability performance. Grid stiffness is higher closer to generating stations since traditional generators (i.e., synchronous machines) produce significant amounts of short-circuit current. This is because system strength (or stiffness) at any location is directly proportional to the magnitude of available short-circuit current; hence, why the metric used for system strength is called Short Circuit Ratio. System strength decreases as distance from a generating station increases. Therefore, remote locations of the transmission system (i.e., farthest from a generating station) have lower SCR and hence are less strong or stiff than locations closer to the generating station. For example, the Lamar Substation in southeastern Colorado is one of the weakest locations in Colorado's transmission system given its remoteness from generation and load.

Historically, traditional fossil-fuel generation resources have served to augment the transmission system strength. However, with Public Service's resource mix rapidly changing as Public Service and the state undergo a major energy transition to increased use of renewable generation resources (i.e., wind, solar, and battery storage), the issue of potentially insufficient system strength will become more pervasive. Renewable resources contribute to low system strength (or "weak bus" in electric power systems parlance) in a couple of ways. First, renewable resources are typically located and connected to remote locations of the transmission system (i.e., at weaker buses). Second, renewable resources interface with the grid through inverters, and are not capable of improving the bus strength.

Since the stability performance of renewable resources is impacted by low system strength, implementing effective mitigation becomes necessary. Typically, such mitigation involves fine-tuning the generating plant's controller settings, which does not involve additional capital investments by the transmission or generation owner. However, this mitigation approach becomes ineffective below a threshold SCR—that is, at an unacceptably weak bus. In such cases, the only viable solution may be to increase the bus strength above the threshold. This requires increasing the available short-circuit current, which can only be accomplished with a synchronous machine. Installing a synchronous condenser is the typical solution for reinforcement of grid/system strength at unacceptably weak transmission buses. This device enables any inverter-based resource interconnected to that bus to achieve acceptable stability performance and thus enhances transmission system reliability.

Q. WHAT FACTORS WILL DETERMINE IF GRID STRENGTH REINFORCEMENT IS NECESSARY TO ACCOMMODATE THE APPROVED PORTFOLIO?

A. The primary factor will be the system strength at locations where generation interconnects – presumably to the Pathway Project - but this could occur at other locations on the transmission system as well. Taking the Pathway Project as an example, since Tundra, Pawnee and Canal Crossing, and Fort St. Vrain Substations are in close proximity to existing generating stations, they have (or will have) relatively strong buses that will not likely need reinforcement. However, Goose Creek and May Valley will be relatively remote substations due to the long transmission lines connecting them to Pawnee and Comanche generating stations. Therefore, these are the most likely locations on the Pathway Project where system strength reinforcement may be needed if generation resources selected in Phase II interconnect at these locations. Although the SCR at these two stations may be above the applicable minimum threshold for system intact conditions, short-circuit studies would determine if the SCR falls below the threshold under credible post-contingency conditions (N-1 and G-1). As I discussed above in Section IV, another important factor that will impact the system strength reinforcement need is the effect of any accelerated fossil-fuel resource retirements Public Service proposes as part of this proceeding and approved by the Commission. Even if there is no need to install synchronous condensers at Goose Creek or May Valley when the Pathway Project is targeted for completion, system strength reinforcement may become necessary due to synchronous generator retirements in the Front Range region occurring by 2030 or beyond. Retirements of fossil-fuel generation (which are machines with inertial spinning masses) coupled with the addition of inverter-based renewable resources will also reduce the available system inertial energy, which would result in adversely impacting the system's frequency stability. With the changing resource mix, it is necessary to ensure we have the right mix of "ancillary services"[10] available at the right times and in the right locations to ensure that grid operations remain stable. Therefore, there are several factors resulting in numerous scenarios that will need to be evaluated in future transmission studies to determine the potential need for installing synchronous condensers on the system.

[10] The term "ancillary services" refers to the collection of attributes (such as frequency control, inertial energy, voltage regulation, and short circuit current) that support a reliable grid by helping maintain system strength, stability, and reliability.

Q. HAS THE COMPANY DEVELOPED ANY PRELIMINARY COST ESTIMATES FOR GRID STRENGTH REINFORCEMENTS?

A. As I said, additional analysis will need to occur to determine potential need as more information is known about the size, location, and other characteristics of any approved resources. However, to provide the Commission with a rough estimate of potential additional transmission costs, the Company has developed an illustrative unit pricing estimate, shown below in Table HS-D-1, which includes costs for facility procurement, installation, work to place the facility in-service, and other related expenses. This example is illustrative for a single type of facility and is not intended to show the full scope of future grid strength reinforcements that may be needed. Again, given that the Company will not be able to specifically identify what (if any) grid strength reinforcements are needed to reliably implement the 2021 ERP & CEP until after a final portfolio is selected and approved, these cost estimates are not part of the Company's cost estimate for the Pathway Project and will be refined in the future, as I discuss below.

Table HS-D-1: Illustrative Unit Pricing Estimate for Grid Strength Enforcement

Synchronous Condenser and Size	Unit Cost Estimate	No. of Units (potential need)
345kV, 550 MVA Megavolt-Ampere "(MVA") Short Circuit Contribution, no specified MVAr output	$52 Million	Two (2)

C. Reactive/Voltage Support

Q. YOU ALSO MENTIONED REACTIVE/VOLTAGE SUPPORT AS ANOTHER CATEGORY OF POTENTIAL ADDITIONAL INVESTMENTS. WHAT DO YOU MEAN AND WHAT FACTORS WILL INFLUENCE THE NEED FOR REACTIVE SUPPORT TO SUPPORT THE 2021 ERP & CEP?

A. Reactive and/or voltage support devices are generally classified into two categories: (1) mechanically switched shunt reactive devices, and (2) power-electronics based dynamic reactive devices. The former type of devices are typically identified based on steady-state analysis, and identification of the need for the latter type of devices requires performing dynamic simulations. The steady-state analysis required to determine the need for shunt inductors (or shunt reactors) is substantially different than what is required to determine the need for shunt capacitors. For its Pathway Project CPCN filing, the Company conservatively included in the Project design and cost estimates the approximate "base" amount of switched shunt reactive devices needed at each substation of the Pathway Project based on preliminary line loadability analyses and engineering judgment. However, the Company anticipates needing additional reactive support facilities to support the 2021 ERP & CEP.

Q. HAS THE COMPANY DEVELOPED PRELIMINARY COST ESTIMATES FOR DYNAMIC REACTIVE/VOLTAGE SUPPORT DEVICES?

A. Yes. Public Service's rough estimate of the additional costs associated with dynamic reactive power/voltage control facilities and grid strength reinforcements *combined* is approximately $150-$250 million. I would describe this cost estimate as a preliminary and illustrative cost estimate at this point, as future studies are needed to refine these cost estimates. Since the reactive power support needed using capacitor banks is greatly influenced by the location and reactive capability of generators, the Company will refine this projected amount in future studies once the 2021 ERP & CEP preferred resource portfolio is identified and approved. At that stage, dynamic studies will also begin to identify the reliability need for one or more dynamic reactive devices, such as one or more StatCom(s). Since dynamic studies require detailed generator models, and the results are greatly influenced by the location, size, and technologies of the inverter-based resources, these studies will provide more realistic results if performed using the approved resource portfolio. Given that the Company will not be able to specifically identify what dynamic reactive power/voltage control facilities (and grid strength reinforcements) are needed to reliably implement the 2021 ERP & CEP until after a final portfolio is selected and approved, these cost estimates are not part of the Company's cost estimate for the Pathway Project and will be refined in the future, as I discuss below.

Q. PLEASE EXPLAIN HOW THE COMPANY HAS DEVELOPED THIS ESTIMATE.

A. Public Service developed this estimate based on the Company's engineering knowledge and experience. We drew in large part from our recent experience with the CEPP approved as part of the 2016 ERP. For example, the CEPP required two StatComs, one at 95 MVAr and one at 150 MVAr. Public Service anticipates that similar dynamic reactive support devices to those installed to support the CEPP approved as part of the 2016 ERP may be necessary to reliably operate its system once the Pathway Project and resources approved in this proceeding interconnect. The Company provides an illustrative unit pricing estimate, shown below in Table HS-D-2, which includes costs for facility procurement, installation at an appropriate site, work to place the facility in-service, and other related expenses. This example is illustrative for a single type of facility and is not intended to show the full scope of future reactive/voltage support that may be needed, and is separate and distinct from the potential grid strength reinforcements I mentioned above.

Table HS-D-2: Illustrative Unit Pricing Estimate for Dynamic Reactive/Voltage Support Devices

Reactive Support Device and Size	Unit Cost Estimate	No. of Units (potential need)
StatCom: 345kV, +/- 200 MVAr	$50 Million	One – Two

Unit costs and any related timelines are based on non-binding and non-final inquiries performed by the Company's engineering team and historic costs for recent facility installation. The cost estimates are unable to reflect site-specific information and do not reflect challenges related to tying into existing facilities or other indirect impacts, such as the need for remote terminals or other ancillary costs, including equipment or building structures.

D. Interconnection Costs

Q. YOU ALSO MENTIONED INTERCONNECTION COSTS AS ANOTHER CATEGORY OF POTENTIAL ADDITIONAL TRANSMISSION INVESTMENTS. WHAT DO YOU MEAN AND HOW WILL PUBLIC SERVICE IDENTIFY THE NEED FOR INTERCONNECTION COSTS ASSOCIATED WITH THE APPROVED PORTFOLIO?

A. The interconnection costs associated with new generation resources will be determined under the LGIP requirements of the Company's FERC-approved OATT. The OATT prescribes a variety of studies that will identify needed facilities and associated interconnection costs.

As part of its Phase II process, the Company will develop indicative cost estimates related to the bids in advance of being able to perform the LGIP required interconnection studies under the OATT. If the Pathway Project CPCN is granted, the new Project substations and endpoints would lend themselves as locations where interconnection costs are minimal. Should a bid offer to interconnect at a different location on the Pathway Project it will be burdened with significantly higher interconnection costs due to the new transmission facilities (i.e. new substation) required for its interconnection. Therefore, the interconnection costs cannot be known or projected until after final bids are received and awarded, and the applicable LGIP studies occur.

Q. WILL THE COMPANY CONTINUE TO EXAMINE THE SYSTEM NEEDS THROUGH THE COURSE OF THE 2021 ERP & CEP?

A. Yes, the Company will continue to study the additional facilities needed to reliably implement the portfolios as they are developed, once they are proposed, and once a portfolio is approved. In parallel, with each of these steps, we will continue to refine these cost estimates.

More specifically, Public Service will prepare more refined transmission cost estimates to support its preferred portfolio identified as part of its ERP 120-Day Report. As part of the Company's 120-Day Report filing, it will present the Commission and stakeholders with a transmission portfolio cost estimate that includes a breakdown of projected costs by category and a discussion of the Company's degree of accuracy surrounding these cost estimates. Once the Commission has approved the resource selection and/or when a generator submits an interconnection request, the Company will then be able to conduct the detailed studies necessary to identify the suite of additional transmission facilities that will be needed to reliably interconnect the selected portfolio and each individual generator. Public Service will bring forward these projects to the Commission through follow-on transmission CPCN application filings, where the Company will be able to present more refined cost estimates than what was presented in the 120-Day Report.

VI. RECOMMENDATION AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. In summary, I recommend the Commission not designate any of the Company's conceptual transmission projects as planned transmission projects for purposes of the Phase II bid solicitation in this 2021 ERP & CEP proceeding. However, as explained by Company witness Ms. Trammell, bidders may propose to interconnect to the Pathway Project without taking on an additional transmission cost burden in the levelized energy cost of their bids.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Statement of Qualifications

Hari Singh

As Principal Engineer at Public Service Company of Colorado since 2009, my responsibilities have included providing subject matter expertise and supervision of job activities comprising the reliability assessment of the Company's transmission system in both planning and operations time horizons. During my 25+ years of work experience, I have conducted several engineering studies involving a wide variety of power system analyses and simulations in order to assess system performance and provide cost effective recommendations for enhancing the reliability of electric power delivery systems. As such, my competencies include a comprehensive and in-depth knowledge of NERC Reliability Standards for Bulk Electric System ("BES") Modeling, Planning and Operations, as well as WECC Regional Reliability Criteria, Study Methodologies and Guidelines.

My technical expertise in planning & operating the BES for reliability performance enhancement is well recognized within the electric power industry. Presently, I contribute in the following industry groups in a leadership position:

- Vice-Chair of NERC Standards Drafting Team responsible for updating Reliability Standards pertaining to System Operating Limits
- Chair of WECC Energy Storage Modeling Task Force
- Chair of WECC Under-Frequency Load Shedding Review Group
- Vice-Chair of WECC Path Task Force

In addition, I have either previously contributed to or actively participate in the following industry efforts:

- Root Cause Analysis for NERC's Investigation of the August 14, 2003 Blackout
- Member of NERC Phase III-IV Planning Standards Drafting Team (2005-06)
- Member of NERC Methods of Establishing Interconnection Reliability Operating Limits Task Force (2016-18)
- Chair of NERC System Analysis & Modeling Subcommittee (2018-2020)
- Member of WECC Modeling & Validation Working Group (since 2009)
- PSCo Representative in WECC Reliability Assessment Committee and WECC Operating Committee
- Vice-Chair of NATF (North American Transmission Forum) Modeling and Planning Practices Group

I obtained my Bachelor's, Master's and Doctoral degrees in Electrical Engineering with emphasis in Power Systems from Panjab University, Indian Institute of Technology and Texas A&M University, respectively. I am a Senior Member of the Institute of Electrical and Electronics Engineers since 1997 and a registered Professional Engineer since 2000.