**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. 21-XXXXE**

DIRECT TESTIMONY AND ATTACHMENTS OF

AMANDA R. KING

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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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2021 ERP & CEP	Public Service's 2021 Electric Resource Plan and Clean Energy Plan
80x30 TF	CCPG 80x30 Task Force
80x30 TF Report	Phase I Transmission Report for the CCPG 80x30 Task Force
AC	Alternating Current
BA	Balancing Authority
BAA	Balancing Authority Area
CCPG	Colorado Coordinated Planning Group
CEPP	Colorado Energy Plan Portfolio
Commission	Colorado Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
DC	Direct Current
DC-tie	Direct Current Tie
DER	Distributed Energy Resources
DSM	Demand-Side Management
EHV	Extra High Voltage
ERP	Electric Resource Plan
ERZs	Energy Resource Zones
ESWG	CCPG Energy Storage Work Group
FERC	Federal Energy Regulatory Commission

Acronym/Defined Term	**Meaning**
GDT Project	Greenwood – Denver Terminal 230 kV Transmission Project
Gen-Tie	Generator Tie Line
HE	Hour Ending
ITC	Investment Tax Credit
kV	Kilovolt
LFR Project	Lamar-Front Range Project
LFRTF	CCPG Lamar-Front Range Task Force
LGIP	Large Generator Interconnection Procedure
mG	Milligauss
MISO	Midwest Independent System Operator
MSSC	Most Significant Single Contingency
NERC	North American Electric Reliability Corporation
NWA	Non-Wires Alternative
OATT	Open Access Transmission Tariff
Pathway Project or Project	Colorado’s Power Pathway 345 kV Transmission Project
PTC	Production Tax Credit
Public Service or Company	Public Service Company of Colorado
ROW	Right-of-Way
Rush Creek Gen-Tie	Rush Creek 345 kV Generator Tie Line
SB07-100	Senate Bill 07-100

Acronym/Defined Term	**Meaning**
SCR	Short Circuit Ratio
SPP	Southwest Power Pool
StatCom	Static Compensator
SPG	Subregional Planning Group
SSPG	Sierra Subregional Planning Group
SWAT	Southwest Area Transmission Subregional Planning Group
TAM	Transmission Asset Management
TCA	Transmission Cost Adjustment
Tri-State	Tri-State Generation and Transmission Association, Inc.
TSR	Transmission Service Request
WECC	Western Electricity Coordinating Council
XES	Xcel Energy Services Inc.
Xcel Energy	Xcel Energy Inc.

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<u>DIRECT TESTIMONY AND ATTACHMENTS OF AMANDA R. KING</u>

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Amanda R. King. My business address is 414 Nicollet Mall, Minneapolis, Minnesota 55401.

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

A. I am employed by Xcel Energy Services Inc. ("XES") as Director, Strategic Transmission Planning. In this role, I support the Company's Transmission Planning and Business Relations divisions. 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"), along with 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. My responsibilities include managing the Reliability Transmission Planning teams in each of Xcel Energy's utility operating companies, Public Service, Northern States Power Company (Minnesota), Northern States Power Company (Wisconsin), and Southwestern Public Service Company. These teams are responsible for maintaining the reliability of the Transmission system, while ensuring compliance with North American Electric Reliability Corporation ("NERC") and Federal Energy Regulatory Commission ("FERC") compliance standards. Additionally, I manage the Regional Transmission Planning and Analytics team. This team is responsible for maintaining relationships with the Regional Transmission Operators, Midcontinent Independent System Operator ("MISO") and Southwest Power Pool ("SPP"), as well as the Western Electricity Coordinating Council ("WECC") and West Connect in Public Service's region. In addition, my team runs production cost modeling software and evaluates regional transmission projects that will reduce congestion on the system to facilitate determination of the most cost-effective generation to run. 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 support the Company's Application to the Colorado Public Utilities Commission ("Commission") for a Certificate of Public

Convenience and Necessity ("CPCN") to construct Colorado's Power Pathway 345 kV Transmission Project (the "Pathway Project" or the "Project").

In Section II of my Direct Testimony, I provide a detailed description of the Pathway Project and its components, which will consist of approximately 560 miles of transmission line, the expansion of three existing substations, the expansion of one planned but not yet in-service substation, and the construction of three new substations. The three new substations will be 345 kV switching stations.

In Section III, I discuss the purpose and need for the Project from a transmission planning perspective, in the context of the Company's upcoming 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP") filing and the Company's and state's decarbonization goals.

In Section IV, I present and explain the transmission expansion planning studies the Company has conducted to determine the specific need for the Project and associated costs, including the efforts the Colorado Coordinated Planning Group ("CCPG") has undertaken to evaluate the Project, particularly through its CCPG 80x30 Task Force ("80x30 TF"). I also outline the future transmission system reliability performance studies that will occur to determine additional transmission facilities (e.g., reactive support, network upgrades, and interconnection facilities) that will be necessary to accommodate the 2021 ERP & CEP.

In Section V, I discuss system alternatives the Company has considered with respect to the Project and the Company's reasons for selecting the Pathway Project as the Preferred Alternative.

In Section VI, I discuss the relationship between the Pathway Project and the Company's previous planning efforts and reports, including the stakeholder engagement and coordination that has occurred and is ongoing.

Finally, in Section VII, I discuss the May Valley-Longhorn transmission line extension option (the "May Valley-Longhorn Extension"), a 90-mile 345 kV, double circuit transmission extension that the Company is presenting in this CPCN filing for Commission consideration. I explain the analysis the Company performed to evaluate this option and support the need for the May Valley-Longhorn Extension. I also discuss the system alternative of generator tie lines with respect to the May Valley-Longhorn Extension.

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

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

- Attachment ARK-1 is a Vicinity Map showing the location of the Project;
- Attachment ARK-2 is a Vicinity Map of the May Valley-Longhorn Extension;
- Attachment ARK-3 is a Map of the Designated Energy Resource Zones ("ERZs");
- Attachment ARK-4 is an overview map of the Colorado Transmission network by ownership; and,
- Attachment ARK-5 is the Phase I Transmission Report for the CCPG 80x30 Task Force ("80x30 TF Report").

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR TESTIMONY?

A. I recommend the Commission find that the Pathway Project is needed from a transmission planning perspective to support the Company's forthcoming 2021

ERP & CEP and issue a CPCN for the Project. I additionally recommend the Commission consider the merits of the May Valley-Longhorn Extension, and if it determines there to be sufficient need and benefit at this time, similarly issue a CPCN for the May Valley-Longhorn Extension in this Proceeding.

II. PATHWAY PROJECT DESCRIPTION

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

A. The purpose of this section of my Direct Testimony is to provide a detailed description of the Pathway Project, including the transmission line and substation facilities the Company plans to construct.

Q. PLEASE PROVIDE AN OVERVIEW OF THE PATHWAY PROJECT.

A. The Pathway Project will consist of approximately 560 miles (which amounts to 1120 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).[1] 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 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 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

[1] 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).

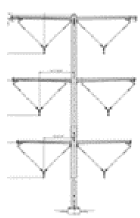
Substation, near the Comanche generating plant. The Project will then run north to the Company's existing Harvest Mile Substation, located adjacent to the City of Aurora in Arapahoe County. As I discuss in more detail below, an additional benefit of the Pathway Project is that it will network a large 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 ("Gen-Tie") connected to Public Service's transmission system at Missile Site Substation. A vicinity map of the Project is provided as Attachment ARK-1 to my Direct Testimony.

In addition, Public Service is presenting a 90-mile, 345 kV transmission extension called the May Valley-Longhorn Extension to the Commission for consideration. 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. I discuss the May Valley-Longhorn Extension in more detail in Section VII of my testimony below. A vicinity map of the May Valley-Longhorn Extension is provided as Attachment ARK-2.

Q. PLEASE DESCRIBE THE TRANSMISSION LINE COMPONENTS OF THE PATHWAY PROJECT.

A. For purposes of this CPCN filing, Public Service has identified the Pathway Project as five segments of 345 kV transmission line. The segments are identified by the substation or switching station endpoints for that portion of the transmission line. Table ARK-D-1 below provides a description by segment (starting at Fort St. Vrain Substation and traveling clockwise):

Table ARK-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 Substation** 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 Canal Crossing Substation.

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 lines.
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 Substation to Goose Creek Substation** 160 miles
	Segment 2 involves constructing approximately 160 miles of new 345 kV double circuit transmission line from the Canal Crossing Substation 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.

Q. HOW WILL THE PATHWAY PROJECT UTILIZE EXISTING TRANSMISSION INFRASTRUCTURE?

A. As described above, three existing substations and one planned but not yet in-service substation will be expanded to accommodate the Project's future interconnections. All other Project facilities will be newly constructed infrastructure. Company witnesses, Mr. Byron R. Craig and Mr. Brian J. Richter discuss the engineering, cost estimates, and construction schedule associated with these substation expansions.

Q. PLEASE EXPLAIN WHY THE NEW CANAL CROSSING SUBSTATION WILL BE CONSTRUCTED ADJACENT TO THE EXISTING PAWNEE SUBSTATION.

A. The new Canal Crossing Substation will essentially be an expansion of the existing Pawnee Substation. However, constraints on the land owned by the Company (namely, an existing canal) require new facilities for the Pathway Project to be sited on land adjacent to the existing Pawnee Substation. The Pawnee Substation will be expanded to accommodate equipment to interconnect with the new Canal Crossing Substation. This will electrically interconnect the Pathway Project to the Company's existing transmission system at Pawnee. The Canal Crossing Substation will be constructed to accommodate equipment and line terminations for the new circuits to/from the existing Fort St. Vrain and new Goose Creek Substations, and new circuits to/from Pawnee.

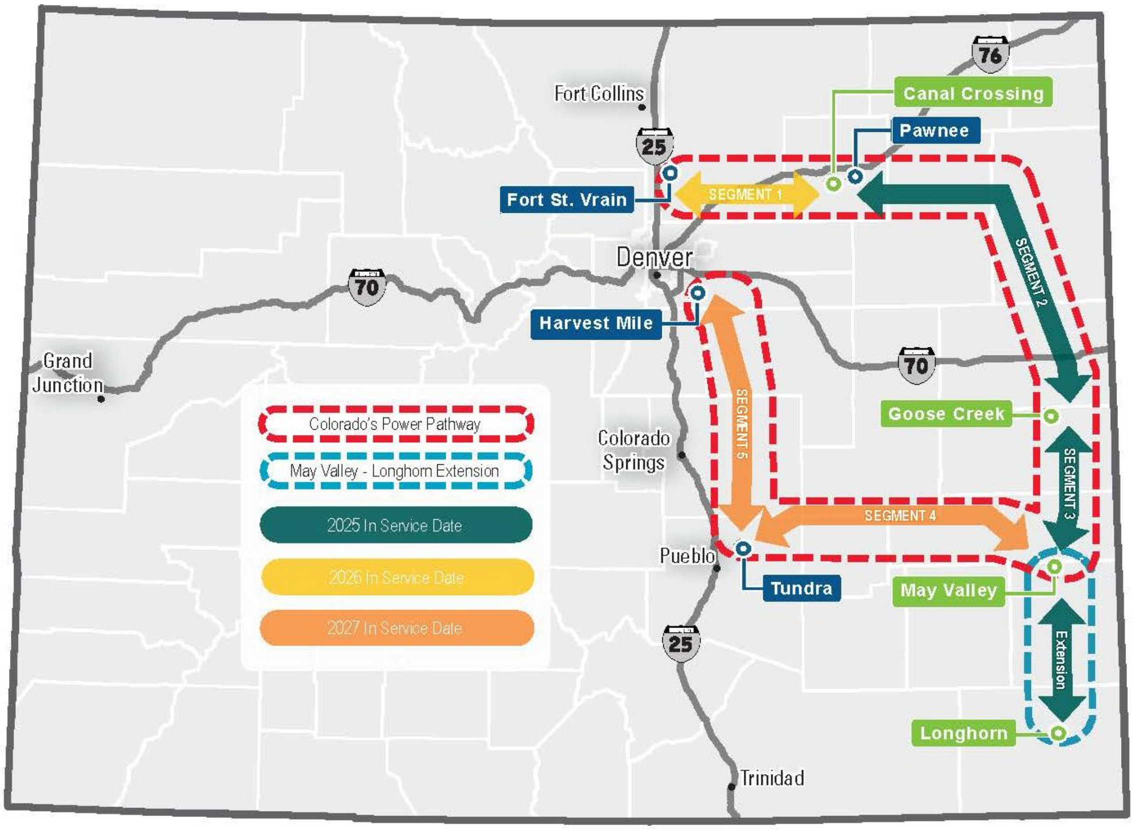
Q. PLEASE ELABORATE ON THE TUNDRA SUBSTATION'S STATUS AS "PLANNED" BUT NOT YET IN-SERVICE.

A. The Tundra Substation is needed to interconnect a solar-plus-storage generation facility approved as part of the Company's 2016 Electric Resource Plan ("ERP") and Colorado Energy Plan Portfolio ("CEPP") (Proceeding No. 16A-0396E). Public Service expects the portion of the Tundra Substation needed to accommodate the generation facilities approved as part of the 2016 ERP's CEPP will be in-service in 2022, prior to the construction of the Pathway Project. Here, the Company proposes to expand the future Tundra Substation as part of the Pathway Project. The initial Tundra Substation design involves tapping an existing 345 kV transmission line to provide interconnection for a new solar-plus-storage generating facility. For the Pathway Project, the Tundra Substation will be expanded to accommodate the proposed 345 kV transmission lines to/from the new May Valley Substation (to the east) and to/from the existing Harvest Mile Substation (to the north). As Company witness, Ms. Brooke A. Trammell explains, the Company will be filing for a CPCN for the Tundra Substation in a forthcoming CEPP interconnection CPCN application this year as it constitutes one of the interconnection facilities needed to implement the CEPP.

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

A. As explained by Company witness Mr. Richter, 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. As Mr. Richter explains, 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. The in-service date for Segment 1 including the Fort St. Vrain Substation expansion of the Project 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 ARK-D-1 below depicts the Company’s planned sequencing for the Project.

Figure ARK-D-1: 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"). As Company witnesses Ms. Trammell and Mr. Jim F. Hill discuss, 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. 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 further clean energy cost savings for customers. As Company witness Ms. Alice K. Jackson explains, 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 a large portion of network the existing Rush Creek and Cheyenne Ridge Gen-Tie line(s), thereby providing improved reliability for the interconnected 1,400 MW 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 will place in service by the end of 2027. These segments will provide improved reliability on the new Pathway Project backbone transmission system.

Q. PLEASE DESCRIBE THE MAY VALLEY-LONGHORN EXTENSION.

A. The May Valley-Longhorn Extension involves constructing approximately 90 miles of new 345 kV double circuit transmission line from the new May Valley Substation, that will be constructed at the southeastern corner of the Pathway Project near Lamar, Colorado south to a new substation located near Vilas, Colorado as shown in the map provided as Attachment ARK-2. The new Longhorn Substation near Vilas will be constructed on land to be acquired by Public Service and would accommodate new 345 kV line terminations and equipment. The May Valley-Longhorn Extension would be constructed for an anticipated in-service date of year end 2025, to allow potential new generation sited in southeastern Colorado to interconnect to the Pathway Project.

The Company is bringing forward this optional extension to the Pathway Project for the Commission's consideration, as it 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. DOES THE COMPANY ANTICIPATE ADDITIONAL TRANSMISSION FACILITIES AND INVESTMENT WILL BE NEEDED TO ACCOMMODATE THE PORTFOLIO ULTIMATELY SELECTED AS PART OF ITS 2021 ERP & CEP?

A. Yes. To be clear, the Pathway Project does not reflect the full range of transmission investment that the Company anticipates will be needed to implement the 2021 ERP & CEP. As I discuss in more detail in Section IV of my testimony below, Public Service anticipates it will need to make additional investments in four categories to support the Pathway Project: (1) network upgrades to enable the delivery of significantly increased generation from additional renewable energy resources into the Denver Metro area "load center" from remote areas, (2) grid-reinforcement equipment at more remote locations of the Pathway Project, (3) reactive/voltage support facilities/equipment to maintain adequate operating voltage during heavy power transfer scenarios and outages, and (4) new interconnection facilities, if needed, based on generator interconnection requests. Public Service has developed preliminary cost estimates for some of these additional investments and will continue to refine the scope and associated cost as uncertainties in study assumptions are narrowed during the ERP process. However, the Company will not be able to fully determine the system reliability needs and associated costs until after the Commission has approved a specific portfolio of generation projects in Phase II of the Company's forthcoming ERP, at which point the Company can conduct the necessary detailed, rigorous transmission reliability studies on the approved portfolio. Put another way, we have rough estimates today, but the location, size, and other characteristics of actual resources selected as part of an approved portfolio in the ERP Phase II competitive solicitation will allow for refinement of the transmission investments needed in addition to the Pathway Project. I discuss these cost estimates in more detail in Section IV of my Direct Testimony.

III. PATHWAY PROJECT PURPOSE AND NEED

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

A. In this section of my Direct Testimony, I describe the purpose and need for the Pathway Project. I address the transmission planning objectives that guided the selection of this Project. I discuss the lack of transmission access in the eastern portion of Colorado and how the scope of the Pathway Project provides the transmission access necessary to reach the renewable-rich areas of eastern Colorado.

A. Overview of Project Purpose and Transmission Planning Goals

Q. WHY IS THE COMPANY PROPOSING THE PATHWAY PROJECT?

A. As explained by Company witness Ms. Jackson and in other parts of the Company's direct case, Public Service is proposing the Pathway Project to facilitate access to the transmission system for generating facilities in areas that are rich with potential for developing renewable energy in eastern Colorado. As I explain below, the Project's looped configuration and geographic scope provide interconnection points for clean energy resources located in the ERZs designated pursuant to Senate Bill 07-100 ("SB07-100"). Company witness Ms. Trammell discusses the policy rationale supporting the ERZs in her Direct Testimony. Further, the Project's characteristics 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 resources to the Company's load centers. A map showing the Company's designated ERZs is attached as Attachment ARK-3 to my Direct Testimony.

The Project will support implementation of the Company's forthcoming 2021 ERP & CEP, which will be developed to comply with the State of Colorado's clean energy objectives of decreasing Public Service's emissions 80 percent by 2030 relative to 2005 levels. Ms. Jackson and Ms. Trammell discuss the Company and State's clean energy policies and goals in more detail. As Mr. Hill explains, the Company anticipates it will need to acquire approximately 3,900 MW (nameplate) of additional clean energy resources to achieve this emission reduction objective. Moreover, and as I explain below, the existing transmission system is unable to reliably accommodate this level of additional renewable generation, particularly from the eastern and southern areas of the state that are most rich in wind and solar resource potential. While Company witnesses Ms. Jackson and Ms. Trammell discuss these and other policy rationales for the Project in more detail, the Pathway Project will provide an extensive, strategic, and networked transmission backbone to accommodate the vast amount of clean energy resources coming online throughout the ERP resource acquisition period that goes out to 2030.

Q. IS THE PATHWAY PROJECT NEEDED FROM A TRANSMISSION PLANNING PERSPECTIVE?

A. Yes. The ultimate objective of transmission planning is to develop a transmission strategy that balances the short-term, mid-term, and long-term needs of retail and wholesale customers, while ensuring cost-effective and reliable electric energy supply. Given the significant expense, time, and physical space that utility transmission infrastructure projects require, it is not always efficient or economical over the long-term to build "just enough" transmission to accommodate the immediate needs of a certain generation project or portfolio of generation. Rather, the Company must consider longer-term goals and objectives that will require transmission build-out, which may involve larger transmission facilities needed to accommodate future generation resources and advance state public policy objectives. When developing and considering a large transmission project, it is important to evaluate and balance the potential future benefits that a project might deliver against the potential costs.

Q. IS THE PATHWAY PROJECT CONSISTENT WITH THESE LONG-TERM PLANNING CONSIDERATIONS?

A. Yes. This forward-looking Project will not only accommodate generation to help meet the State of Colorado's and Public Service's 2030 clean energy target, but it will form the bedrock for future development that will be necessary to meet the State's and the Company's next target of achieving 100 percent clean energy by 2050. Moreover, the Project will create a new networked transmission loop across the eastern plains of Colorado, providing greater system reliability and operational benefits than a series of long radial lines or gen-ties.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY A "NETWORKED" TRANSMISSION FACILITY.

A. A transmission facility is networked if there is more than one path to deliver the electricity from the source to the load. Networked "backbone" transmission is inherently more reliable than radial transmission because it provides more than one path for energy delivery from generation to load, and therefore is better positioned to withstand transmission outages without causing significant loss of generation output or significantly degrading the transmission system's power transfer capability to deliver generation to load. The more paths there are between the generation and the load, the greater the system reliability. A "backbone" system generally refers to bulk transmission lines networked together that can move large amounts of energy from distant generation resource location(s) to load center(s). A system of networked bulk transmission lines is what is commonly referred to as the electrical "grid."

Q. PLEASE COMPARE THE OPERATIONAL AND RELIABILITY BENEFITS OF NETWORKED TRANSMISSION FACILITIES VERSUS LONG GEN-TIES.

A. Connecting generation to a system of networked transmission lines is a superior arrangement to a series of gen-ties both from the perspective of keeping generation online and for ensuring load can be served. Connecting generation through long radials or gen-ties has two significant drawbacks. First, the delivery of generation to load is dependent on one transmission line where a single contingency (i.e., an "N-1" scenario) could take the generation offline. Networked transmission, on the other hand, provides additional transmission pathways to load centers, meaning that generation can remain online in an N-1 scenario, as there is an alternate pathway available to deliver generation to load. A transmission system should be planned so it will continue to operate reliably if one of the facilities is taken out of service or has a failure. Second, single transmission elements, such as gen-ties, have a higher risk during an outage of not being able to deliver interconnected generation to load.

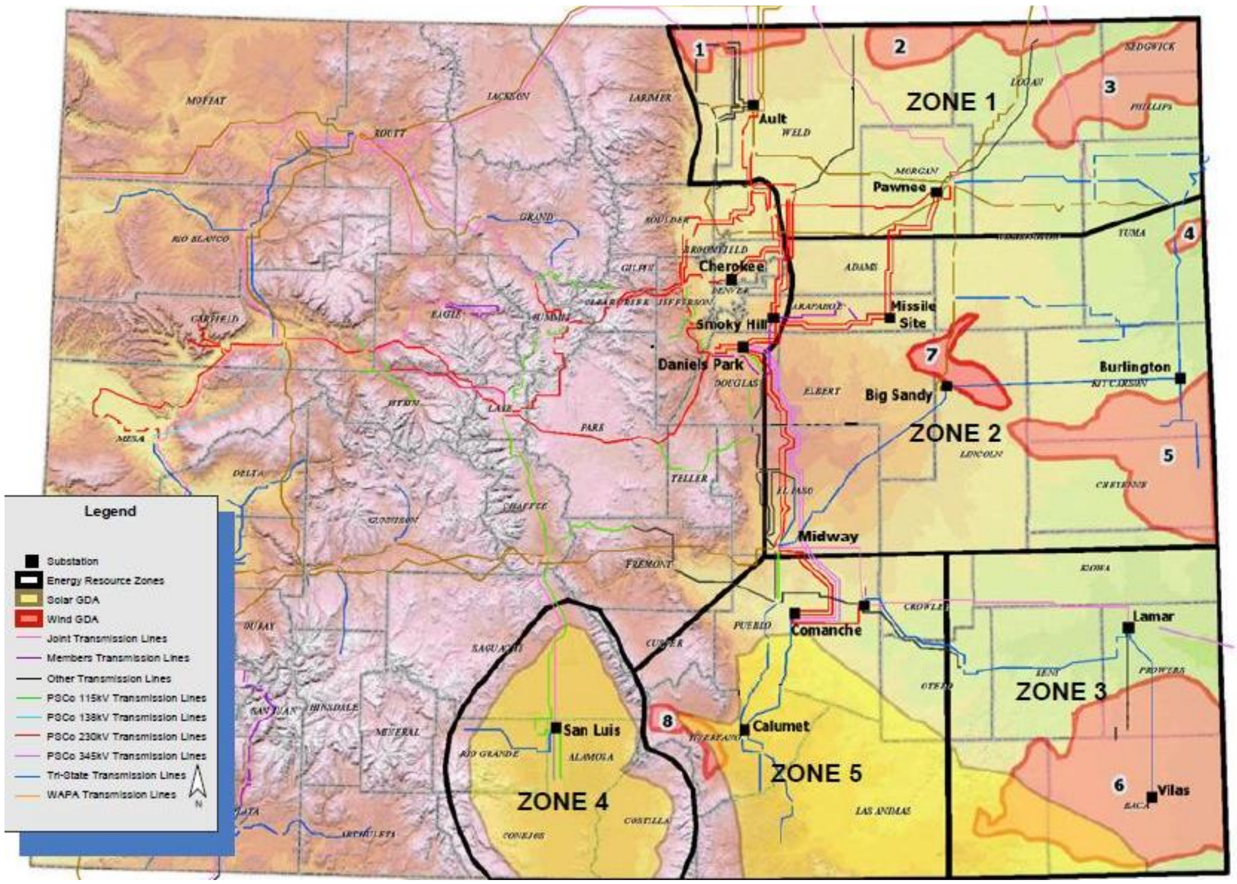
Q. DOES THE PATHWAY PROJECT DESIGN MEET THE APPLICABLE NERC RELIABILITY STANDARDS?

A. Yes. In fact, the Pathway Project has been purposefully designed as a looped system to meet or exceed the system performance requirements for the single and multiple contingencies specified in all applicable NERC reliability standards.

Q. IF THE PATHWAY PROJECT IS NOT DEVELOPED, HOW DO YOU ANTICIPATE TRANSMISSION WOULD BE DEVELOPED TO ACCOMMODATE NEW GENERATION RESOURCES IN THE EASTERN AND SOUTHERN PORTIONS OF THE STATE?

A. Attachment ARK-4 to my Direct Testimony is a map of the transmission facilities in Colorado, and Figure ARK-D-2 below shows the ERZs in Colorado.

Figure ARK-D-2: Colorado's ERZs



As Attachment ARK-4 shows, there is very limited transmission available in the eastern portion of Colorado. In fact, there is virtually no Company-owned 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 major, strategic transmission resource in eastern Colorado, generators would be left to develop, on an ad-hoc and uncoordinated basis, long radial lines or gen-ties to interconnect dispersed clean energy resources to the existing transmission network. This approach has numerous drawbacks from a transmission planning and operations perspective and should be avoided, as I discuss in more detail below.

B. Transmission Limitations in Eastern Colorado

Q. PLEASE DISCUSS THE UNIQUE ATTRIBUTES OF PUBLIC SERVICE'S TRANSMISSION SYSTEM IN COLORADO.

A. The Company's transmission system, and Colorado's transmission system generally, is somewhat unique. Colorado is at the eastern edge of the Western Interconnection of the North American electric power grid, also known as the WECC. As such, with very limited exceptions, the Company's transmission system is not interconnected with other transmission facilities to the east.[2] Large transmission interconnections such as the WECC or the Eastern Interconnection are very large transmission systems that each work as separate synchronized systems. In other words, Public Service in the WECC operates asynchronously from the Eastern Interconnection. Each of these regions' synchronizations is unique to that region. For example, Colorado could not just build a transmission line that directly connects to the Eastern Interconnection because the two systems (WECC and the Eastern Interconnection) are not synchronized with each other. To make such a connection, highly specialized and expensive equipment called Direct Current Ties ("DC-ties") are necessary. A DC-tie allows the electricity from one interconnection system to be converted to direct current power, which can then be transformed on the other side of the DC-tie to alternating current ("AC")

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[2] The Company's transmission system is interconnected with that of its utility operating company affiliate, Southwestern Public Service Company, in the Eastern Interconnection, via the Lamar HVDC tie.

and synchronized with the other system. It is only through these specialized connections that Colorado could electrically connect eastward.

Another unique feature of Public Service's system is Colorado's topography and geography. Colorado's largest load center—the Denver Metro area—is located on the Front Range of the Rocky Mountains. The Rocky Mountains to the west present a geographical constraint to transmission construction—both from a construction and engineering perspective, as well as from a siting, land rights, and permitting perspective, thus putting Colorado in a unique transmission planning position. Because of these constraints, the Company's transmission system has traditionally been planned and built to deliver electricity generated more locally, historically from coal-fired generating stations to the Company's retail service territory.

Q. PLEASE PROVIDE MORE DETAIL ABOUT THE TRANSMISSION CONSTRAINTS AND LIMITATIONS IN EASTERN COLORADO THAT LIMIT ADDITIONAL GENERATION DEVELOPMENT.

A. As is clear from Attachment ARK-4, the existing transmission network in eastern Colorado is overall quite sparse (regardless of ownership). The existing transmission system in this area primarily consists of 115 kV transmission lines used for local load-serving needs, and is supported by a few 230 kV transmission lines forming a loop connecting northern and southern Front Range transmission through eastern Colorado. There are no networked Extra High Voltage ("EHV") transmission facilities (i.e., 345-765 kV according to the Department of Energy) in eastern Colorado that are typically required to transport larger amounts of electric power across longer distances.

There are only three existing 230 kV transmission paths for transferring electric power between eastern Colorado and the general vicinity of the Front Range. Two of these 230 kV lines are 100 percent owned by Tri-State Generation and Transmission Association, Inc. ("Tri-State"): the Burlington-Wray-Story 230 kV line and the Burlington-Big Sandy-Midway 230 kV line. These two Tri-State lines have generation resources interconnected at various locations and are also used for local load-serving reliability needs. The third line, the Lamar-Boone 230 kV line, is jointly owned by Tri-State and Public Service. The Lamar-Boone 230 kV line provides transmission access solely for existing generation resources interconnected at the Lamar Substation. None of these existing 230 kV transmission lines has significant remaining capacity available for transferring electric power from eastern Colorado to the Company's Front Range load centers. And, there is no transmission currently extending from Lamar north to the Cheyenne Ridge or Burlington locations.

The Company has recently extended its Rush Creek Gen-Tie, and this facility now runs from the Cheyenne Ridge Wind Project in eastern Colorado to interconnect with the Company's networked transmission system at Missile Site substation in Arapahoe County. However, this radial 345 kV transmission line effectively has no remaining capacity due to the existing 1,400 MW (nameplate) of interconnected wind resources.

Essentially, the transmission system in the eastern part of the State of Colorado is "full." This proposition is supported both by the last ERP and the transmission investment needed to implement that portfolio, as well as the CCPG 80x30 TF Report (provided as Attachment ARK-5 to my Direct Testimony), which I discuss further in Section IV of my testimony. Company witnesses Ms. Jackson and Mr. Hill also address this issue and provide support for the conclusion that the transmission system in eastern Colorado is "full."

C. Need and Benefits of the Pathway Project

Q. WHAT ARE THE BENEFITS OF NETWORKING THE EXISTING CHEYENNE RIDGE TO MISSILE SITE GEN-TIE?

A. One of the key reliability benefits of networking a large portion of the existing 153-mile Cheyenne Ridge to Missile Site Gen-Tie will be to enable the interconnected 1,400 MW of wind generation not to be entirely lost due to a single contingency (N-1) event involving the outage of any line segment between Cheyenne Ridge and Missile Site. Further, since the networked line will allow interconnected generation to be injected into the Public Service transmission system at both the new Goose Creek Substation and Missile Site, the Most Severe Single Contingency ("MSSC") for Public Service's Balancing Authority Area ("BAA") would no longer be the potential loss of 1,400 MW of generation.[3] Since the operating reserves requirement depends on the MSSC, which in turn is determined by the largest

[3] Public Service's electric system is a registered Balancing Authority ("BA") and is subject to all NERC compliance standards applicable to BA operations. NERC standards cover BA planning and coordination, operating reserve requirements, contingency response, reserve restoration, balancing requirements, frequency response, outage coordination, and many other aspects of daily operation of the Bulk Electric System.

generating unit that is on-line, the MSSC would therefore no longer exceed 765 MW (the rated output of Comanche 3). This would significantly reduce the operating reserves requirement for the BAA—which is an important operational benefit. Networking a large portion of the Cheyenne Ridge to Missile Site Gen-Tie will also enhance the Company's ability to schedule planned outages of transmission facilities to perform maintenance, by reducing or eliminating the reliability impacts associated with the existing radial line. In addition to these reliability and operational benefits, customers will benefit from avoided curtailment costs.

Q. DID THE COMPANY ADD NEW TRANSMISSION FACILITIES TO ACCOMMODATE NEW GENERATION RESOURCES SELECTED IN THE 2016 ERP AND CEPP?

A. Yes. The Company's last ERP was filed in May 2016 and the Commission issued a Phase II Decision in September 2018 approving the CEPP.[4] The transmission facilities needed to accommodate these resources included voltage control facilities, certain network upgrades (specifically, the Greenwood – Denver

[4] *See* Proceeding No. 16A-0396E, Decision No. C18-0761 (mailed Sept. 10, 2018). The approved CEPP includes the early retirement of two coal-fired generating facilities with a combined generating capacity of approximately 660 MW, the addition of approximately 1,100 MW of wind generation, approximately 800 MW of solar, 275 MW of storage, and 383 MW of existing gas generation. Some of these resources are already in-service, while others are still under construction.

Terminal 230 kV Transmission Project ("GDT Project")),[5] and generator interconnection facilities.[6]

Q. ARE THESE NEW TRANSMISSION FACILITIES SUFFICIENT FOR THE NEW GENERATION CONTEMPLATED IN THE FORTHCOMING 2021 ERP & CEP?

A. No. The transmission facilities I described above are designed to accommodate the new generation and generation retirements associated with the previously-approved CEPP. These transmission facilities will not provide sufficient transmission capacity for future additional generation resources. As noted by Company witness Mr. Thomas W. Green in Proceeding No. 20A-0063E, the proposed 15-mile, 230 kV GDT Project will allow the Company to implement the addition of the CEPP generation resources, but will not provide capability for adding more utility-scale generation resources along the 345 kV system in the Front Range.[7] As I stated above, the system in this part of the State of Colorado is "full."

[5] *See* Consolidated Proceeding Nos. 19A-0728E & 20A-0063E, Decision No. C20-0648 (mailed Sept. 10, 2020), in which the Commission granted CPCNs for the CEPP Voltage Control Facilities and GDT Project, and approved the underlying Settlement Agreement.

[6] As Ms. Trammell discusses, the Company is still preparing its CPCN application(s) for the interconnection facilities, which it expects to file later in 2021. The planned Tundra Substation will be a component of that application.

[7] *See* Consolidated Proceeding Nos. 19A-0728E & 20A-0063E, Hr. Ex. 107, Direct Testimony of Thomas W. Green (originally filed Feb. 21, 2020), at 7:17-22, 10:1–11:14, and 36:3-8.

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 be determined through the Company's forthcoming 2021 ERP & CEP process and potentially other future utility actions, too.

Q. HOW HAS THE COMPANY EVALUATED THE RESOURCES THAT WILL BE NEEDED TO ACHIEVE AN 80 PERCENT BY 2030 EMISSION REDUCTION, AND THUS DRIVE THE NEED FOR THE PATHWAY PROJECT?

A. As explained by Company witness Mr. 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 resource planning group forecasts the upcoming 2021 ERP & CEP will result in the addition of approximately 3,900 MW (nameplate) of wind and solar resources, not including 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. 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.

As I discuss below, these transmission constraints were recognized several years ago and provided the motivation for the initial evaluation of a Lamar-Front Range project in 2013.

Q. WHY IS IT APPROPRIATE THE PATHWAY PROJECT BE PURSUED NOW FROM A TRANSMISSION PLANNING PERSPECTIVE?

A. As discussed by Mr. Hill, Public Service anticipates that in its Phase II competitive solicitation for the 2021 ERP & CEP, a significant number of competitive solar and wind resource developers will submit bids with proposed points of interconnection along the general path of the Pathway Project. In addition to the policy drivers that Ms. Jackson and Ms. Trammell discuss in more detail, it is prudent practice from a transmission planning perspective to engage in this type of coordinated, strategic, and advanced planning effort. Transmission facilities, which may be hundreds of miles long, take longer to construct than generation resources, so it is difficult—if not impossible—to have a transmission line ready when new generation resources are ready to come online without proactive planning and development. This is particularly the case where the transmission facilities are not identified to be constructed until after generation resources have been offered, thus not allowing some resources to be selected if they cannot connect to a nearby transmission facility. Moreover, transmission development does not happen overnight, and the regulatory process adds considerable lag to the development of transmission. By issuing a CPCN now, the Commission will enable more timely development of the Pathway Project's needed transmission facilities in advance of the generation resulting from the 2021 ERP & CEP.

D. <u>The Scope of the Project Is Necessary to Achieve Its Goals</u>

Q. HOW MUCH NEW GENERATION WILL THE PATHWAY PROJECT ACCOMMODATE?

A. As I discuss below in Section IV, the Company's transmission studies have shown that, as designed, the Project will be able to reliably integrate approximately 3,000-3,500 MW of electric power output from new generation. This electric power output figure can also be referred to as the "injection capability" of the Project, and is not reflective of the nameplate generation capacity the Project will be able to accommodate, which will be higher than these figures. This 3,000-3,500 MW injection capability assumes that new generation injection is almost equally divided between the northeastern generation areas (i.e., approximately 1,500 MW injection between the proposed new Goose Creek Substation adjacent to the existing Cheyenne Ridge Wind Project collector station and the proposed new Canal Crossing Substation adjacent to Pawnee) and the southeastern/southern generation areas (i.e., approximately 1,500 MW injection between the proposed new May Valley Substation near the existing Lamar Substation and the Pueblo area near the Tundra Substation).

Q. ARE YOU ABLE TO QUANTIFY HOW MUCH NAMEPLATE CAPACITY THIS TRANSLATES INTO?

A. Without more information about the actual resources that will interconnect to the line, there is not really an accurate way to "convert" or otherwise correlate a networked line's injection capability into a maximum nameplate capacity value. Injection capability at any system location is inherently a moving target that varies with the prevailing system conditions characterized by system load level and economic generation dispatch. This is primarily driven by: (1) the non-coincident production of wind and solar at system peak times, and (2) the hourly output capacity and interconnection locations of each interconnected generation resource. I discuss this issue in more detail, and provide several illustrative comparisons of nameplate capacity versus injection capability/dispatch, in Section IV below.

IV. TRANSMISSION PLANNING STUDIES

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 that have been performed by and through the sub-regional planning group, the CCPG. I explain that the CCPG launched the 80x30 TF so that all stakeholders could work together to collaboratively identify transmission backbone infrastructure needed access ERZs 1, 2, 3 and 5 and advance Colorado utilities toward meeting the state's emission reduction goals, and that the Pathway Project emerged as the Company's Preferred Alternative from the 80x30 TF's study efforts for reasons I discuss below. I also discuss studies that the Company will conduct in the future after specific resources are selected in Phase II of the 2021 ERP & CEP and the additional transmission investments that are anticipated to be required.

A. The CCPG 80x30 TF Study

Q. WHAT IS THE CCPG?

A. The CCPG is a joint, high-voltage transmission system planning forum.[8] Its purpose is to assure a high degree of reliability through cooperative planning, development, and operation of the high-voltage transmission system in the Rocky Mountain Region of the WECC. The CCPG provides a technical forum to complete reliability studies and accomplish coordinated planning under the single-system planning concept. The CCPG has the authority to sanction studies through task

[8] The CCPG, the Southwest Area Transmission ("SWAT") Subregional Planning Group, and the Sierra Subregional Planning Group ("SSPG") perform the transmission planning functions as Subregional Planning Groups ("SPGs") under WestConnect, which is a FERC Order No. 1000 planning region. The CCPG is one of at least five SPGs recognized by WECC.

forces made up of CCPG members and any interested stakeholders. Task forces are generally developed to evaluate major transmission or policy issues. A task force will determine scope and study objectives, which in turn guide transmission reliability studies and develop proposed findings or recommendations.

Q. DID THE CCPG LAUNCH A TASK FORCE TO EXAMINE COLORADO'S OBJECTIVE TO ACHIEVE AN 80 PERCENT REDUCTION IN RETAIL ELECTRIC UTILITY EMISSIONS RELATIVE TO 2005 LEVELS BY 2030?

A. Yes. The CCPG launched the 80x30 TF in August 2020 to provide a platform for all stakeholders to collaboratively identify transmission infrastructure that will enable Colorado's electric utilities, including Public Service, to meet the state's emission reduction goals. Through its efforts, the 80x30 TF identified transmission that enables generation delivery from renewable resource-rich areas that lack significant transmission access, including northeastern, eastern, and southeastern Colorado.

Q. WHAT WERE THE OBJECTIVES OF THE CCPG 80X30 TF?

A. The purpose of the 80x30 TF was to identify and propose a transmission plan that would enable Colorado utilities to bring forward generation portfolios in their respective ERP cycles that can achieve the General Assembly's goal of reducing carbon emissions associated with retail electricity sales by 80 percent from 2005 levels by 2030, as set forth in Senate Bill 19-236.[9] This work culminated in the

[9] *See* § 40-2-125.5, C.R.S.

80x30 TF Report (Attachment ARK-5). At a high level, the objectives of the 80x30 TF were to produce a transmission plan that could:

- Accommodate generation resources necessary to meet 2030 carbon reduction goals;
- Maintain geographic diversity of generation resources; and,
- Ensure system reliability and minimize system impacts.

More specifically, the 80x30 TF developed the following goals to meet the broad objectives identified above:

- Facilitate transmission access to new clean energy resources in eastern Colorado located in or near the areas the Company has designated as ERZs 2 and 3 identified per SB07-100;[10]
- Enable the delivery of electric power output from new clean energy resources located in or near designated ERZs 1, 2, 3, and 5 to the load centers along the Front Range;
- Provide new interconnection points to facilitate development of new clean energy resources located in or near ERZs 1, 2, 3, and 5; and,
- Achieve adequate reliability and operational flexibility of the resulting interconnected transmission system in Colorado for enabling significantly increased penetration of new clean energy resources.

Q. PLEASE DESCRIBE THE CCPG 80X30 TF'S STUDY PROCESS.

A. The study performed for the 80x30 TF Report was a transmission steady state power flow study to assess future transmission needs, often referred to as a transmission expansion planning study. This study started with a benchmark case, which included the Company's existing transmission system and transmission

[10] *See* § 40-2-126, C.R.S. An "energy resource zone" is a "geographic area in which transmission constraints hinder the delivery of electricity to Colorado consumers, the development of new electric generation facilities to serve Colorado consumers, or both." The Company's ERZs have been identified to the Commission in the Company's reports submitted pursuant to SB07-100.

facilities expected to be in-service during the study horizon (through 2030). The benchmark case modeled potential new generation from the 2021 ERP & CEP being injected at two existing substations (Pawnee and Comanche Substations). These two substations were selected because they are the nearest 345 kV injection locations (i.e., points of interconnection) for the renewable generation in ERZs 1 and 2 and ERZs 3 and 5, respectively, that could enable interconnection via gen-ties to Public Service's transmission system in the absence of new transmission.

The study then examined a series of new transmission-build alternatives, evaluating the adequacy and system reliability performance of each alternative to accommodate potential generation resources as well as whether the alternative met the 80x30 TF's objectives and goals identified above. For each alternative, the study assumed certain MW injection levels and locations representing potential new generation that could be procured in the ERP process, and transmission facility configurations corresponding to those potential new resources. The power flow analysis was run for each alternative. I discuss the alternatives below in Section V.

Q. WHAT ASSUMPTIONS WERE MADE IN THE 80X30 TF'S STUDY MODELS?

A. The study used system model base cases developed by the WECC, including WECC's base case scenario and 2030 peak summer condition for the Western

Interconnection.[11] Transmission and generation facilities planned to be in-service by 2030 were added, and changes to the transmission network, customer loads, and generation resources were adjusted for those system conditions to reflect known changes. Additional known new transmission facilities included in the 80x30 TF study include:

- Missile Site – Pronghorn – Shortgrass 345 kV Gen-Tie (in-service)
- Pawnee – Daniels Park 345 kV Transmission Project (in-service)
- PSCo Voltage Control Facilities for the Colorado Energy Plan (in-service)
- Waterton – Martin 115 kV line uprate (2021)
- Monument – Flying Horse 115 kV series reactor project (2023)
- Greenwood – Denver Terminal 230 kV Line (2022)
- CSU transformer project at Briargate (2023)
- Tundra 345 kV Switching Station (2022)

Likewise, generation resources were also updated to reflect all existing generation and resources planned to be installed in the study horizon, 2020-2030, which are included in the base model. The planned generation in the benchmark study case includes:

- Cheyenne Ridge 500 MW wind (in-service)
- Bronco Plains 300 MW wind (in-service)

[11] WECC is a non-profit corporation that exists to assure reliability within the bulk electric system in the Western Interconnection. WECC has been approved by FERC as the regional entity for the Western Interconnection and has a variety of members, including transmission owners, energy service providers, end-users, and government representatives. Among other things, WECC works with utilities and transmission providers to develop transmission models that provide members with base case data they can then utilize to conduct more focused and/or utility-specific transmission model runs.

- Mountain Breeze 169 MW wind (in-service)
- Niyol 200 MW wind (2021)
- Thunderwolf 200/100 MW solar/storage (2022)
- Neptune 250/125 MW solar/storage (2022)
- Hartsel 72 MW solar (2022)
- Colorado Energy Plan generator at Boone/Midway 200 MW solar (2022)
- Spanish Peaks I 100 MW solar (2023)
- Spanish Peaks II 40 MW solar (2023)

Q. DID THE 80X30 TF'S STUDY ADHERE TO APPLICABLE RELIABILITY STANDARDS?

A. Yes. The 80x30 TF's study adhered to all applicable Reliability Standards set forth by NERC and Regional Criteria published by WECC, as discussed in the 80x30 TF Report. The Company's planning criteria similarly adhere to these Reliability Standards and Regional Criteria. In the study, facility loadings and voltages were monitored consistent with these NERC Reliability Standards and WECC Regional Criteria, which require that following a contingency outage and/or disturbance on the system, the power loading and voltages on transmission elements must remain within acceptable limits.

Q. PLEASE DESCRIBE THE 80X30 TF STUDY'S BENCHMARK CASE MODELING.

A. As discussed in the 80x30 TF Report, the study began with a power flow analysis to determine the system impacts due to 3,000 MW of output from new clean energy generation being injected into the transmission system. The power flow study to support this benchmark case looked at facilities planned to be in-service by 2030, not including the proposed Pathway Project (i.e., the benchmark case).

For the benchmark case, the model assumed that new generation would be injected into Public Service's system in the Pawnee area (including the Pawnee, Story, and Brush Substations) and the Comanche area (including the Comanche, Tundra, Mirasol, and Midway Substations), since the three new substations comprising the Pathway Project do not exist in the benchmark case. The new generation's output was equally divided between the Pawnee and Comanche areas (approximately 1,500 MW each), consistent with the study objective of promoting geographical diversity of resources.

Q. PLEASE DESCRIBE THE 80X30 TF STUDY'S MODELING OF THE TRANSMISSION ALTERNATIVES.

A. As discussed in the 80x30 TF Report, the Task Force analyzed seven transmission project alternatives beyond the benchmark case. As discussed below, for each alternative, the study models assumed that the majority of the 3,000 MW output from new generation would be injected into the Public Service system at the new Goose Creek Substation, the new May Valley Substation, and the Comanche/Tundra Substation(s), based on expected locations for potential new renewable generation. Study models were developed for each alternative by adding the associated transmission facilities for each alternative. Power flow analysis was performed on each study model to evaluate how well each alternative would meet the study's objectives as well as the system reliability criteria.

Q. PLEASE EXPLAIN THE 80X30 TF'S MODELING OF 3,000 MW OF NEW RENEWABLE GENERATION.

A. The 80x30 TF modeled generation dispatch[12] of 3,000 MW of new renewable generation along with 3,000 MW of existing renewable generation on the Company's system to meet the 80 percent carbon emissions reduction goal by 2030.

As I mentioned earlier, the aggregate *nameplate* capacity of the renewable resources that were modeled for 3,000 MW dispatch of renewable generation will be higher than 3,000 MW. Since wind and solar are inherently variable energy resources, not fixed capacity resources, their typical coincident MW output is much smaller than their aggregate nameplate MW. Unlike traditional fossil resources, the MW output from wind and solar generating plants may individually approach their respective nameplate MW rating for certain hours, but for most hours their aggregate coincident MW output will not approach their aggregate nameplate MW rating. Therefore, it was determined that for prudent transmission planning, the study should be based on a reasonable assumption of 3,000 MW *dispatch* from new renewable resources, which will be significantly lower than the theoretical maximum MW output of the resources' nameplate capacity.

[12] The 80x30 TF Report refers to the model as "dispatching" 3,000 MW of new renewable generation in the model. However, this does not mean that the new renewable generation facilities would be dispatchable (or able to be called upon on demand) without storage.

Q. HOW DID THE COMPANY'S UPCOMING 2021 ERP & CEP INFLUENCE THE 80X30 TF'S STUDY MODELING?

A. Based on the Company's resource planning projections, which are described in detail by Company witness Mr. Hill, the 80x30 TF considered the Company's resource acquisition targets of approximately 2,300 MW of wind, 1,600 MW of solar, 400 MW of storage, and 1,300 MW of dispatchable (i.e., fossil fuel) resources for a total of 5,600 MW (nameplate) of resources. As I noted above, of the 5,600 MW of projected resource acquisitions by the Company, the 80x30 TF focused on the injection of 3,000 MW of new renewable resources needed to meet the 2030 emission reduction goals.

Q. WHY DID THE 80X30 TF STUDY 3,000 MW OF RENEWABLE (WIND AND SOLAR) GENERATION DISPATCH, WHILE THE COMPANY'S PROJECTED RENEWABLE RESOURCE ACQUISITION IS APPROXIMATELY 3,900 MW?

A. The approximately 3,900 MW represented by Mr. Hill is a *nameplate* rating, which refers to the full potential output of a generating resource. However, the output from variable renewable resources generally only approaches the resource's nameplate capacity during limited hours, if at all; this is somewhat analogous to a generation unit's capacity factor. The 80x30 TF analyzed the simultaneous dispatch of resources necessary to serve the peak summer load projected in the WECC 2030 summer peak case. The simultaneous dispatch of these resources is in most hours significantly lower than the aggregate nameplate capacity of these same resources. Therefore, it was determined that the 80x30 TF's study should be based on a reasonable assumption of 3,000 MW coincident injection or output from new renewable resources, and not on the theoretical maximum of 3,900 MW nameplate capacity (or 4,900 MW).[13]

Q. YOU MENTIONED COINCIDENT INJECTION OR OUTPUT. PLEASE ELABORATE ON THAT CONCEPT.

A. The "injection," or output, refers to the amount of electric energy produced by the generation facility and injected into the grid. The term "coincident" refers to the output levels produced at the same time by more than one generator or more than one type of generators.

The injection capability determined for a given location is highly dependent on the assumed generation dispatch pattern. Therefore, the maximum injection capability corresponds only to the most favorable system condition expected to occur, which is not a valid metric for the actual injection capability, as this rarely occurs. In the past, due to a very limited set of typical generation dispatch patterns associated with the economic dispatch of conventional resources (e.g., coal, gas, and hydro), transmission injection capability would typically fall within a narrower range and could be determined with a high level of certainty. However, with increasing levels of variable resources integrated into the Company's BAA, the resulting generation dispatch patterns have become increasingly variable. Assigning a single injection capability to any location is unrepresentative of the actual capability at that location given that the injection capability range has a wider

[13] The CCPG considered approximately 1,000 MW (nameplate) of new renewable resources for purposes of other utilities' carbon reduction goals for the study. I discuss the potential for additional utility partners in the Project below. Company witnesses Ms. Jackson and Ms. Trammell discuss the potential partnership in more detail.

spread due to the highly variable dispatch patterns associated with wind and solar resources. Determining a maximum injection capability is akin to marking one bookend of the wide range of variable injection capability resulting from myriad combinations of variable loads and variable generation dispatch patterns. This is also the reason it is not appropriate to simply add up standalone injection capabilities for purposes of evaluating transmission reliability.

Q. COULD YOU PROVIDE AN EXAMPLE TO HELP ILLUSTRATE THIS CONCEPT?

A. Yes. Suppose that the Company had 2,400 MW (nameplate) of solar resources and 3,600 MW (nameplate) of wind resources. These types of resources generally would not provide 100 percent of their nameplate capacity at the same time as each other. Solar resources tend to produce greater output in the afternoon, Hour Ending ("HE") 1500 or 3 p.m., and little to no output in the evening and night-time, HE2300 or 11 p.m. By contrast, on-shore wind resources generally produce greater output in the evening and night-time hours. To plan its system, the Company would need to know the coincident generation output of these 6,000 MW (nameplate) of renewable resources. Table ARK-D-2 below provides an illustrative example.

Table ARK-D-2

6000 MW Name-Plate Generation	Coincident Generation Output during Summer Peak Load Hours 1300-2300 Hours in June-Aug (PSCo BA Load ~10,000 MW)				
	HE1500	**HE1700**	**HE1900**	**HE2100**	**HE2300**
Solar = 2400 MW	100%	90% (2160)	60% (1440)	30% (720)	0%
Wind = 3600 MW	25% (900)	40% (1440)	60% (2160)	80% (2880)	100%
Total Output	3300 MW	3600 MW	3600 MW	3600 MW	3600 MW

As shown in Table ARK D-2, even though the generating resources have a nameplate capacity of 6,000 MW, these resources would not be expected to have a coincident output greater than 3,600 MW.

To study the merits of the backbone Project, the Company reduced the existing dispatchable and renewable resources currently on the system to enable 3,000 MW of new renewable resources to be added along the Pathway Project. It is not likely that the system will see 3,000 MW of output from new renewable resources at peak based on the potential 3,900 MW resource acquisition target. This level of injection demonstrates there is headroom available after 2030.

Q. DID THE 80X30 TF DEVELOP A REPORT TO DOCUMENT ITS FINDINGS?

A. Yes, the 80x30 TF Report (Attachment ARK-5) details the Task Force's studies and findings. After summarizing the purpose and the objectives of the study, the 80x30 TF Report explains the study's methodology, including the transmission and generation modeling. The bulk of the 80x30 TF Report sets forth the results of the analyses conducted in the study, including the benchmark case and seven transmission alternatives studied. The 80x30 TF Report also explains how cost estimates for the alternatives were developed.

Notably, the 80x30 TF Report finds that the existing system is "unable to reliably accommodate new generation in ERZs 1, 2, 3, and 5, and is therefore unable to accommodate 2030 carbon reduction goals."[14] Accordingly, the 80x30 TF Report determines that a new wide-area 345 kV transmission project

[14] Attachment ARK-5, at 13-14.

interconnecting at multiple locations on the Company's and potentially other utility transmission systems in the northeastern, eastern, and southeastern portions of the state, with transmission access into the Denver Metro area, would accommodate potential generation necessary to meet the state's 2030 carbon reduction goals. Further, the 80x30 TF Report concludes that the Pathway Project (identified as Alternative 3 in the 80x30 TF Report) "would significantly improve reliability of the Colorado transmission network" by "providing additional high voltage transmission through the eastern portion of Colorado."[15]

Q. HOW HAS THE COMPANY IMPLEMENTED THE RESULTS OF THE 80X30 TF STUDY IN THE PLANNING AND DESIGN OF THE PROJECT?

A. The Company has developed the Pathway Project consistent with Alternative 3 from the 80x30 TF Report. It meets the reliability needs of the system and enables increased levels of new renewable generation from all of ERZs 1, 2, 3, and 5.

Q. HOW WILL THE PATHWAY PROJECT BE ABLE TO ACCOMMODATE ADDITIONAL UTILITY PARTNERS IF PUBLIC SERVICE ULTIMATELY PURSUES A PARTNERSHIP, AS DISCUSSED BY COMPANY WITNESSES MS. JACKSON AND MS. TRAMMELL?

A. From a design perspective, the 80x30 TF study identified Alternative 7, which included an additional endpoint at the existing Story 345 kV and Lamar 230 kV Substations. Alternative 3 (which is the Pathway Project) could be modified to add interconnections at Story and Lamar as shown in Alternative 7, should Tri-State

[15] Attachment ARK-5, at 32.

choose to utilize a portion of the Project to meet its public policy and local reliability needs. If other utilities join as partners, those would be factored into the need for, and configuration of, the Project as well. As such, future Phase II 80x30 TF studies may identify additional endpoints to support the participation of other utility partners. Ms. Trammell explains the procedural process for how any participating Commission-regulated utility partners will present applications for CPCNs to the Commission, and how those applications will address each utility's own needs, capacity allocation, any additional facilities each utility proposes to construct in connection with its own CPCN, and any additional studies that support the utility-specific facilities.

From an injection capability standpoint, as the 80x30 TF study demonstrated, the Pathway Project will accommodate 3,000-3,500 MW injection of new renewable generation resources. Given the variable nature of these resources, the renewable resource needs of additional utilities may be met by a percentage participation/ownership in the Pathway Project. Though the injection of renewable resources will remain unknown until actual resource acquisition decisions are made, the injection of potentially 3,900 MW (nameplate) is well within the injection capability limits of what was studied, leaving the opportunity for other utilities to also meet their clean energy needs.

B. Future Transmission Investment and Studies

Q. DOES PUBLIC SERVICE ANTICIPATE ANY ADDITIONAL TRANSMISSION INVESTMENT WILL BE NEEDED TO SUPPORT THE PATHWAY PROJECT AND RELIABLY IMPLEMENT THE 2021 ERP & CEP?

A. Yes. 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. This fundamental shift in how, where, and when electricity is generated—especially as generation moves to more remote areas—is driving new challenges that transmission planners are grappling with. 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 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 to support the Pathway Project beyond what is included in this CPCN application, in four 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 high cost 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, transmission studies will continue and in fact must continue subsequent to this CPCN proceeding as Public Service moves through each phase of the forthcoming 2021 ERP & CEP.

More specifically, as part of the 2021 ERP & CEP, 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. After the Commission approves an ERP resource portfolio, the Company will then perform specialized and more granular performance assessment studies on a systemwide 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 static compensator(s) ("StatCom") necessary to enable reliable system operation during a variety of generation dispatch and credible contingency scenarios.

If Public Service develops the Project on its own, in its capacity as a Transmission Provider it will concurrently perform generator interconnection studies as the generation developers that bid into the 2021 ERP & CEP submit interconnection requests in accordance with Public Service's FERC-approved Open Access Transmission Tariff ("OATT"), through the Large Generator Interconnection Procedure ("LGIP") and/or Transmission Service Request ("TSR") procedures. This process might work slightly differently if there are multiple utility owners or investors, but would still need to follow FERC-approved OATT LGIP and TSR procedures. During these studies, Public Service will determine the interconnection facilities and network upgrades needed to interconnect the new generation to the transmission system (i.e., for receiving interconnection service), for each generator that submits an interconnection request (including those from the 2021 ERP & CEP resource acquisitions approved by the Commission). This is typically followed by the associated TSR study, which determines the network upgrades needed to reliably deliver the generation output to load.

1. Denver Metro Area Network Upgrades

Q. PLEASE EXPLAIN HOW THE COMPANY IDENTIFIED THE POTENTIAL ADDITIONAL INVESTMENT ASSOCIATED WITH THE DENVER METRO AREA UPGRADES AND PREPARED COST ESTIMATES.

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, which is based on the Company's transmission planning experience and judgment. 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. 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 80x30 TF Report (Attachment ARK-5). However, the specific engineering scope of network upgrades that would effectively mitigate the overloads has not been determined and will depend on the Company's approved resource portfolio. More specifically, the identified overloads may change, but it is premature to explore the feasibility of optimal mitigation solutions. Additional power flow studies for the approved resource portfolio will confirm the anticipated overloads and required transmission capacity increases, which in turn will help scope the required network upgrades followed by cost estimates for the resulting optimally engineered projects.

For example, in regard to the transmission facilities needed to accommodate the 2016 ERP portfolio, an alternative better optimized transmission project (the GDT 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.

2. <u>Grid Strength Reinforcement</u>

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 (“SCR”). 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 renewable 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 adversely 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 WOULD DETERMINE IF GRID STRENGTH REINFORCEMENT THROUGH A SYNCHRONOUS CONDENSER IS NECESSARY FOR THE PATHWAY PROJECT?

A. As explained above, the primary factor will be the system strength at each of the Pathway Project locations where prospective generation interconnects. Since Tundra, Pawnee/Canal Crossing, and Fort St. Vrain Substations are in close proximity to existing generating stations, they 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 where system strength reinforcement may be needed. 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). Another important factor that will impact the system strength reinforcement need is the effect of any accelerated fossil-fuel resource retirements proposed by the Company in the 2021 ERP & CEP 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 in 2027, 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"[16] 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 at Goose Creek or May Valley Substations.

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

A. The Company's overall cost estimates for the Pathway Project do not include estimated costs for grid strength reinforcements. This is because 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 illustrative unit pricing estimate, shown below in Table ARK-D-3, 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 grid strength reinforcements that may be needed.

[16] 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.

Table ARK-D-3

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

3. 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?

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 this CPCN filing, the Company has 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 Pathway Project. The Company anticipates needing approximately $150-$250 million in combined additional reactive support facilities and grid strength reinforcements to reliably operate the Pathway Project once a final 2021 ERP & CEP generation resource portfolio has been approved. Again, this rough cost range is in addition to what is included in the CPCN cost estimate.

These figures are based on preliminary unit cost estimates to procure these types of devices, install them at an appropriate site, and perform work to place the facilities in-service. 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 in to existing facilities or other indirect impacts, such as the need for remote terminals or other ancillary costs, including equipment or building structures. Due to the extent of project definition (i.e., unknowns regarding exact location of approved generation), these estimates are not the result of the same rigor and review that the Company will perform prior to filing for its follow-on CPCN(s). 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 2021 ERP & CEP approved resource portfolio.

Q. PLEASE PROVIDE ADDITIONAL INFORMATION ABOUT THE "BASE" REACTIVE/VOLTAGE SUPPORT FACILITIES INCLUDED IN THE COMPANY'S PROPOSAL.

A. Company witness Mr. Craig addresses the physical assets, including the switched shunt reactive support facilities that are included in the planned engineering and design for the Project. As noted by Mr. Craig, these "base" reactive/voltage support facilities are included in the Project cost estimate.

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

A. Yes. As I mentioned above, 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. Although the Company has not, and cannot at this time, identify the specific dynamic reactive support that will be needed, future studies are likely to conclude that these devices may be necessary.

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. While the Pathway Project is electrically different than the Rush Creek/Cheyenne Ridge Gen-Tie, Public Service anticipates that similar dynamic reactive support devices to those installed to support the CEPP may be necessary to reliably operate its system once the Pathway Project is in-service and more variable energy generation is added to the system. The Company provides an illustrative unit pricing estimate, shown below in Table ARK-D-4, 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.

Table ARK-D-4

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

4. 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?

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.

Under the ERP Phase II process, the Company will develop Indicative cost estimates related to the bids in advance of being able to perform the LGIP's required interconnection studies under the OATT. Since the Company is proposing the new Project substations and endpoints, interconnections should be available at these locations. Should a bid offer to interconnect at a location other than to existing facilities, those bids will be burdened with the additional transmission costs of new transmission facilities required for interconnection. While the Company would expect interconnection costs to be lower than those needed to implement the CEPP given the new substation facilities we are proposing to construct as part of the Pathway Project, these 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 AS THE PROJECT PROGRESSES THROUGH THE 2021 ERP & CEP?

A. Yes, the Company will continue to study the additional facilities needed to reliably implement the 2021 ERP & CEP, and in parallel, will continue to refine these cost estimates. First, 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. These costs will be accounted for in the evaluation of various resource portfolios to inform the Commission’s ultimate determination of a cost-effective resource plan under the ERP Rules. 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. Accordingly, Public Service will bring forward these cost estimates to the Commission through follow-on transmission CPCN filings, where the Company anticipates it will be able to present Scoping-level cost estimates as set forth in Company witness Mr. Richter's Direct Testimony.

Q. ARE THERE WAYS THE COMPANY WILL KEEP THE COMMISSION AND STAKEHOLDERS UPDATED ON THE PROGRESS AND STATUS OF ITS STUDY RESULTS AND COST ESTIMATES?

A. Yes. The Company will continue to keep stakeholders informed through regularly-scheduled CCPG and FERC Order No. 890 meetings. Additionally, studies conducted pursuant to the Company's LGIP in its OATT will be published on its OASIS website. From a procedural perspective, and as Ms. Trammell outlines, the Company will provide more refined transmission cost estimates for these four categories of costs as part of its 120-Day Report. The Company will perform more detailed planning studies after a Phase II ERP decision issues that approves the final resource plan portfolio. Following these studies, Public Service will file follow-on transmission CPCN applications with supporting cost estimates for these additional transmission investments.

V. PROJECT ALTERNATIVES

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

A. In this section of my Direct Testimony, I discuss the alternatives the Company considered to the development of the Pathway Project.

Q. DOES THE COMMISSION REQUIRE CPCN APPLICANTS TO CONSIDER ALTERNATIVES TO THEIR PROPOSALS?

A. Yes. Commission Rule 3102(b)(VIII) requires that an applicant provide, "as applicable, information on alternatives studied, costs for those alternatives, and criteria used to rank or eliminate alternatives."

Q. DID THE TRANSMISSION PLANNING TEAM STUDY ANY ALTERNATIVES TO THE PATHWAY PROJECT?

A. Yes, consistent with Rule 3102(b)(VIII), the Company, in conjunction with the CCPG 80x30 TF, studied six alternatives in addition to the option that became the Pathway Project. Also, the development of the benchmark case could be considered a seventh alternative of "do nothing."

Q. PLEASE DESCRIBE THE BENCHMARK CASE.

A. The Phase I study started with a benchmark case, which included the Company's existing transmission system and transmission facilities expected to be in-service during the study horizon: 2020-2030. Generation was then added to the benchmark case at locations available on the system but without additional transmission, which amounts to a study of a "status quo" or "do nothing" alternative. As set forth in the 80x30 TF Study (Attachment ARK-5), the analysis of the benchmark case shows the current system through the planning horizon cannot meet the state's and Company's carbon reduction goals. More specifically, the benchmark case shows the existing transmission system, even with planned additions through 2030, will be unable to reliably serve new generation in ERZs 1, 2, 3, and 5, and therefore unable to achieve the Company's clean energy target for 2030 under Senate Bill 19-236. Specifically, past studies have shown that no generation could be accommodated at the existing Cheyenne Ridge (collector station) and Lamar Substations and only limited generation could be accommodated at the Pawnee, Tundra, Missile Site, Midway, Comanche, and Boone Substations.

Q. PLEASE DISCUSS THE ALTERNATIVES TO THE PATHWAY PROJECT THAT THE COMPANY HAS CONSIDERED.

A. In conjunction with the CCPG 80x30 TF, Public Service studied a total of seven alternatives that would enable the Company to meet the 80 percent carbon emissions reduction goal by 2030. The Pathway Project is identified as Alternative 3 in the 80x30 TF Report. The other six alternatives were not pursued for reasons discussed below (and described in more detail in the 80x30 TF Report).

- **Alternative 1**: Does not meet the study goal of facilitating increased generation access in ERZ 3 in the southeastern part of the Company's system, including in the vicinity of the existing Lamar Substation.
- **Alternative 2:** Although Alternative 2 met the study goals for generation access in all of ERZs 1, 2, 3, and 5, however, it created a reliability concern under one of the NERC contingency parameters.
- **Alternative 4**: While Alternative 4 meets the study goals for generation access in all of ERZs 1, 2, 3, and 5, the Alternative 4 study results showed higher reactive support requirements than Alternative 3.

- **Alternatives 5, 6 and 7**: While Alternatives 5, 6, and 7 also meet the study goals for generation access in all of ERZs 1, 2, 3, and 5, these Alternatives include transmission configurations that contain additional substation interconnections above Alternative 3. Therefore, they each have more costs than Alternative 3. Although the Company is presenting Alternative 3 in this CPCN application, the CCPG 80x30 TF recognizes Alternative 7 is suitable for meeting the objectives of generation access in ERZs 1, 2, 3, and 5 should Tri-State choose to partner in the Project. The additional substation endpoints in Alternative 7 are not on Public Service's system, which would impact non-Public Service customers. There would also be other considerations such as timing, partnership agreements, and constructability should these locations be selected for substation interconnections by potential project partners.

Q. DID THE 80X30 TF ESTIMATE THE COST OF THESE ALTERNATIVES?

A. Yes. For the 80x30 TF Report, the cost estimates were derived from unit cost estimates using MISO's MTEP20 Transmission Cost Estimation Guide. The estimates focused on transmission line mile costs and did not include new interconnection substations or existing substation expansions. The cost estimates for each alternative are identified in the 80x30 TF Report.

Q. WHAT CRITERIA DID THE COMPANY CONSIDER IN EVALUATING THESE ALTERNATIVES THAT LED TO THE SELECTION OF THE PROPOSED PROJECT?

A. Based on the study objectives—including resource geographic diversity and minimization of thermal and voltage violations on the underlying transmission system—Alternative 3 emerged as the top performer and was thereby selected as the recommended preferred Alternative. Specifically, Alternative 3 provided the overall best study results from a reliability and resource diversity perspective by demonstrating several benefits, including: producing the least amount of identified thermal and voltage violations when compared to the other Alternatives; providing access to the currently transmission-constrained wind generation development area of ERZ 3; establishing a reliable looped transmission system configuration; and retaining partial transmission capacity even under double circuit common tower outages. Additionally, Alternative 3 provides a robust 345 kV backbone to facilitate new generation development in eastern Colorado, which will reduce the necessary mileage of gen-tie lines that developers might otherwise be required to build to access the transmission network. Finally, Alternative 3 was identified to have the greatest and most cost-effective injection and transfer capability, with opportunities for future expansion as the industry moves toward a carbon-free future.

Q. HAS THE COMPANY CONSIDERED A “BUILD NOTHING” ALTERNATIVE?

A. Yes. As I explained above, the 80x30 TF study modeled a benchmark case, which did not add any additional transmission facilities beyond those that are already planned to be in-service during the study horizon. The benchmark case analyzed the effects of adding new generation facilities to the Company’s transmission system, but without adding new transmission—in other words, a “do nothing” scenario with respect to transmission. As noted in the 80x30 TF Report, the benchmark case would not be able to accommodate the addition of generation resources that would be needed to achieve the goal of 80 percent carbon emissions by 2030. As stated earlier, adding more renewable generation to the system without a backbone transmission system providing the access from eastern Colorado would leave developers with the burden of developing very long gen-ties or locating renewable resources in areas around existing transmission that have inferior wind sources. This scenario would most likely lead to burdening the Company's customers with extra costs in the long run.

Q. WHY IS PUBLIC SERVICE PROPOSING TO CONSTRUCT THE PROJECT AT 345 KV?

A. The 345 kV voltage level is consistent with the Company's transmission lines that already terminate or interconnect at existing substations that are part of the Project and the existing facilities at the substations themselves—that is, the Harvest Mile, Tundra, and Pawnee Substations. In addition, the existing 345 kV Rush Creek and Cheyenne Ridge Gen-Tie(s) will interconnect at the new Goose Creek Substation. Adopting the same voltage as existing end points for transmission expansion reduces the cost of substations by minimizing or eliminating the need for transformers. Developing the project at 230 kV would not capture the economies of scale given 230 kV transmission would only provide approximately 50 percent of the transmission capacity achieved with 345 kV.

Q. WHAT OPTIONALITY WILL THE 345 KV DOUBLE CIRCUIT PROVIDE THE COMPANY FROM A TRANSMISSION PLANNING PERSPECTIVE BEYOND THE 2021 ERP & CEP?

A. The construction of the Project at 345 kV will provide the Company greater optionality and flexibility beyond the current 2030 planning horizon. While no studies have been performed for unknown future conditions, the Pathway Project is a major stepping stone to future expansion of the transmission system in Colorado. Another way to view this 345 kV backbone project is as a "no regrets" plan.

Q. DID THE COMPANY CONSIDER CONSTRUCTING THE PATHWAY PROJECT AT 500 KV?

A. Yes, but for a variety of reasons the Company determined that 500 kV transmission is not a reasonable option to pursue at this time.

Q. UNDER WHAT CONDITIONS WOULD THE COMPANY CONSIDER 500 KV?

A. Factors the Company would need to consider include the functional compatibility of a 500 kV alternative with project purpose, viability of timely construction, and the economics/cost considerations. I discuss each these factors in turn.

First, 500 kV transmission generally serves an "expressway" or "superhighway" for large quantities of electric power to flow over long distances and therefore functions well when there are no intermediate substations along the path between the injecting generation source and the load center. For example, if the Company were trying to flow the entire electric output from a large nuclear facility in Wyoming or New Mexico directly to the Denver Metro area, a 500 kV might be a possible transmission solution. However, one of the principle purposes of the Pathway Project is to enable the interconnection of many generating resources to the Company's system, which requires the placement of substations along the transmission route. These substations and generator interconnections reduce the benefits of constructing 500 kV transmission facilities.

Second, 500 kV transmission facilities would take longer to construct. They involve additional work and complexity related to the size of the structures, a wider right-of-way ("ROW") and larger land area for substations, and have higher noise and magnetic field levels. Additionally, routing and permitting a transmission line within a wider ROW, with larger structures, and with higher noise and magnetic fields may require a longer period of time to complete when compared with a 345 kV transmission line due to potential permitting complexities and opposition from the public. This would push the expected in-service dates of the Project later (e.g., into the 2027-2030 time period). This timeframe would jeopardize the ability of generation developers to take advantage of the PTC and ITC incentives, as discussed in more detail by Company witness Mr. Hill. Beginning to place the Project in-service in 2025 is foundational to why we pursued the Project at 345 kV.

Third, a 500 kV transmission system would be notably more expensive. The Company estimates that construction costs for a 500 kV system would be approximately 25-35 percent higher than for 345 kV. The Company would need to acquire more land in fee for the larger footprint of 500 kV substations and would need to acquire additional easement area for the wider ROW needed for the larger 500 kV transmission structures. A 500 kV transmission system may also cause interconnecting generators to incur much higher interconnection costs and experience greater complexity due to the potential need for two stages of transformation (and an intermediate step-up voltage), plus a possible 500 kV gen-tie, for the proposed resources to interconnect to the Company's 500 kV system.

Last, the Company also anticipates that operations and maintenance costs for 500 kV facilities would be more expensive and potentially more complicated. This would be due, in part, to the novelty of a 500 kV system in Colorado, which would require additional training for Company crews that do not have experience with a 500 kV system, and the availability and interchangeability (or lack thereof) of 500 kV equipment with equipment used for the rest of the Company's system.

Q. ARE THERE ANY OTHER REASONS WHY THE COMPANY DID NOT PURSUE THE PROJECT AT 500 KV?

A. Yes, another reason is 500 kV transmission's lack of compatibility of with or strategic role in the surrounding regional transmission grid within the time horizon of the Pathway Project. As I explained earlier, 500 kV transmission generally serves as an "expressway" or "superhighway" for large quantities of electric power to flow over long distances. Consequently, 500 kV transmission is usually an integral part of a strategic regional transmission plan to enable export/import of electric power with entities in neighboring states. This entails identifying potential interconnections to the existing (or planned) 500 kV transmission within the regional transmission plan. There is no existing/planned regional 500 kV transmission in the vicinity of the Pathway Project—the only 500 kV line in Wyoming is several hundred miles away and there is no 500 kV transmission in Colorado's other neighboring states. Therefore, building the Pathway Project at 500 kV would not accomplish any strategic regional goal with potential benefit to Colorado. In fact, as explained earlier, the Pathway Project built at 500 kV would be incompatible with its principle purpose of providing transmission access to clean generation resources and facilitating their interconnection to Colorado's transmission grid.

Q. WHY IS THE COMPANY PROPOSING TO CONSTRUCT THE PROJECT AS A DOUBLE CIRCUIT TRANSMISSION LINE INSTEAD OF SINGLE CIRCUIT?

A. In past studies performed under CCPG through the Lamar-Front Range Task Force ("LFRTF"),[17] many of the Project alternatives were developed as single circuit lines. It was based on this past study knowledge that we determined double circuit lines offer greater capacity and reliability benefits than single circuit lines. For example, changing the new Goose Creek to Canal Crossing line (Segment 2) from single-circuit to double-circuit eliminated the need to site, permit, and construct a new single-circuit line route from Cheyenne Ridge to Missile Site. This achieves cost reduction without compromising the reliability benefits of adding two new generation-outlet circuits for the Cheyenne Ridge-area generation.

Similarly, changing the May Valley to Comanche area (Tundra) line (Segment 4) from single-circuit to double-circuit will improve the transmission access capacity and reliability for Lamar area generation by providing two generation-outlet circuits to the west.

The line segment between Goose Creek and May Valley doubles the available transmission outlets for generation in the Cheyenne Ridge and Lamar area. The resulting networked topology from Fort St. Vrain to Pawnee / Canal Crossing to Goose Creek to May Valley to Tundra to Harvest Mile enhances the transmission reliability for generating resources in ERZs 1, 2, 3, and 5.

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[17] *See* Lamar Front Range Task Force – Study Report (May 21, 2020), *available at* https://doc.westconnect.com/Documents.aspx?NID=19096.

As I have already mentioned, transmission planning needs to include the short-term, mid-term, and long-term view of system needs, and the double circuit design does just that.

Q. TO WHAT EXTENT HAS PUBLIC SERVICE CONSIDERED UNDERGROUNDING THE PATHWAY PROJECT IN WHOLE OR IN PART?

A. Due to both technical and economic implications, the Company does not believe that undergrounding the Pathway Project is reasonable. First and foremost, it would be cost-prohibitive to underground such an extensive transmission project, as discussed in Company witness Mr. Craig's Direct Testimony. Also, the technical issue relevant to transmission planning is the significantly higher charging MVAr (reactive power) produced by underground cables when used in AC systems, by an order of magnitude greater than overhead lines. The charging MVAr increases with system voltage level as well as with distance, and hence rapidly reaches very high levels for EHV transmission (such as 345 kV) that typically traverses long distances. This excessively large amount of charging MVAr produced by AC underground cables must be "neutralized" at regular intervals with reactive devices that counteract its effect, or else the voltage at terminating stations would rise to an unmanageable and unacceptably high level. Mitigation for this would require building several intermediate substations to install necessary reactive compensation along the length of the undergrounded EHV transmission, which further renders AC underground transmission both technically challenging and economically prohibitive. Such technical challenges are absent for underground transmission in direct current ("DC") systems, which makes undergrounding a viable option for high voltage DC transmission lines.

Q. DID PUBLIC SERVICE EVALUATE ANY NON-WIRES ALTERNATIVES ("NWA") OR STORAGE ALTERNATIVES?

A. Yes. It is important to consider the context for the development of the Pathway Project—i.e., to support the Company's upcoming ERP cycle, which will include our CEP. As explained by Company witness Mr. Hill, the Company is forecasting approximately 400 MW of storage (in addition to additional demand-side management ("DSM") measures and distributed energy resources ("DERs") that will be achieved outside the ERP process). In this way, Public Service is considering the role of storage as a generation resource for purposes of its forthcoming 2021 ERP & CEP.

Public Service did consider storage resources as a potential alternative to transmission facilities comprising the Pathway Project; however, it quickly became evident that fundamentally, storage does not offer a reasonable alternative from a technical or practical perspective. The 80x30 TF Report describes the limitations of energy storage technologies for purposes of meeting the goal of 80 percent carbon reduction by 2030. The analysis concluded that there is not a relevant energy storage application suitable to deliver the resources from remote ERZs to the Front Range. As I previously stated, the Company anticipates integrating approximately 3,900 MW of new renewable generation onto its system through the 2021 ERP & CEP. This magnitude of energy delivery from ERZs into load centers requires physical connections; therefore, energy storage technology is inadequate and non-viable as an NWA to the transmission project proposed here.

Q. DOES THE COMPANY'S DECISION NOT TO PURSUE AN NWA OR STORAGE ALTERNATIVE IN THIS CASE MEAN THAT IT WILL NOT CONTINUE TO CONSIDER SUCH SOLUTIONS IN THE FUTURE?

A. No. First, as I noted, the Company is pursuing storage as part of its upcoming ERP cycle. Even though Public Service did not identify a storage alternative to the Pathway Project, Public Service and Xcel Energy continue to evaluate storage and other NWA, such as energy efficiency, DERs, micro-grids, DSM measures, and other emerging technologies, which Mr. Hill addresses in his Direct Testimony.

CCPG has established a working group—the Energy Storage Work Group ("ESWG")—to analyze the benefits and challenges for energy storage and other NWA technologies. The ESWG began meeting in 2020 and the Company will continue to study the potential role of storage and non-wires transmission alternatives going forward.

I would also note that the Company has actively studied storage applications through its Panasonic and Stapleton Innovative Clean Technology Projects, and will be piloting how batteries can provide energy during peak hours, perform solar time shifting, and store energy during low cost production hours through the DSM Residential Battery Demand Response Pilot.

Q. BASED ON THE 80X30 TF STUDIES PERFORMED TO DATE AND THE ALTERNATIVES CONSIDERED, WHAT DO YOU CONCLUDE WITH RESPECT TO THE COMPANY'S PREFERRED ALTERNATIVE, ALTERNATIVE 3?

A. Alternative 3 is a transmission project identified by the 80x30 TF Report that would significantly improve the reliability of the Colorado transmission network. Alternative 3 would improve reliability by providing additional high voltage transmission through the eastern portion of Colorado by making available greater access to and support of the existing transmission currently serving the Denver Metro area. Alternative 3 could be modified to add interconnections at the existing Story, Burlington, and/or Lamar Substations.

VI. CONSISTENCY OF THE PATHWAY PROJECT WITH PUBLIC SERVICE'S PREVIOUS PLANNING EFFORTS

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

A. In this section of my Direct Testimony, I discuss the relationship between the Pathway Project and the Company's previous planning efforts, including the stakeholder engagement and coordination that has occurred and is ongoing.

Q. HAS PUBLIC SERVICE COORDINATED THE PLANNING OF THE PATHWAY PROJECT WITH OTHER UTILITIES?

A. Yes. As I discussed above, the Pathway Project arose from a study that was undertaken under the auspices of CCPG and the 80x30 TF. The 80x30 TF had its first meeting in October 2020 with the objective of identifying transmission plans that would enable the Company to achieve its 80x30 carbon emission reduction goals, and has held a total of seven meetings to date. Stakeholders who have participated in the 80x30 TF's meetings and processes include Colorado transmission owners and utilities (Public Service, Black Hills Energy, Colorado Springs Utilities, Platte River Power Authority, and Tri-State), Staff of the Commission, consumer interest organizations, renewable generation developers, conservation and environmental organizations, and others.

Q. HAVE ANY COMPONENTS OF THIS PROJECT BEEN CONSIDERED AND STUDIED IN PREVIOUS TRANSMISSION PLANNING EFFORTS?

A. Yes. As I mentioned above, portions of the Pathway Project have their origins within the Lamar-Front Range Project ("LFR Project"). The LFR Project was first conceptualized and studied in 2012-2013 as one of several SB07-100 transmission projects intended to deliver electric power consistent with the timing of the development of beneficial energy resources in or near designated ERZs. Since 2013, the LFR Project has been included as a conceptual transmission project in filings at the Commission, first in Public Service's SB07-100 status reports, and later in Public Service's and Tri-State's long-range transmission plans reported in Rule 3627 filings.

In 2019, CCPG created the LFRTF in response to system changes due to generation and transmission projects planned and implemented since 2013, as well as the continued need to evaluate transmission alternatives to help drive emission reductions. The LFRTF considered several standalone transmission segment proposals that focused on staged transmission development in eastern Colorado. The best-performing standalone alternatives led to the combined alternatives of the LFR Project conceptual plan. The benefits of the standalone and/or combined transmission alternatives were measured primarily in terms of how much incremental generation injection any alternative could accommodate under system impact and contingency conditions. However, the LFRTF did not select any preferred standalone or combined transmission alternative since the incremental injection assumptions associated with the study were unsubstantiated by any projected resource acquisition plan(s). Instead, the LFRTF elected to summarize general system performance observations to help guide future transmission analysis and development.

Q. DOES THE PATHWAY PROJECT LEVERAGE ANY OF THE ALTERNATIVES IDENTIFIED FOR THE LFR PROJECT?

A. Yes. The Pathway Project is the outcome of further refinements and augmentation of one of the many combined alternatives evaluated in the LFRTF study for facilitating transmission access to new carbon-free resources in eastern Colorado. The combined alternative 3B plus 7B evaluated by the LFRTF consisted of the following four 345 kV lines: Cheyenne Ridge to Missile Site, Cheyenne Ridge to Story to Pawnee, Lamar to Cheyenne Ridge, and Lamar to Badger Hills, plus some lower-voltage transmission facilities. The Pathway Project topology resulting from the proposed Goose Creek – Canal Crossing, Goose Creek – May Valley, and May Valley – Tundra 345 kV lines is well-aligned with the topology created by the four 345 kV lines comprising the combined alternative 3B-7B. This is because the Pathway Project, as well as the combined alternative 3B-7B, share these common attributes: (1) two new 345 kV transmission lines for providing transmission access to prospective new generation at Goose Creek (effectively the same as Cheyenne Ridge)—that is, two new generation-outlet lines heading northwest out of Goose Creek / Cheyenne Ridge; and, (2) two new 345 kV transmission lines for providing transmission access to new generation at May Valley (effectively the same as Lamar)—that is, two new generation-outlet lines out of Lamar, one line heading west to the Comanche area (i.e., Tundra and Badger Hills) and one line heading north to Goose Creek / Cheyenne Ridge.

Q. HOW IS THE PROPOSED PROJECT PREFERABLE AS COMPARED TO THE ALTERNATIVES EVALUATED BY THE LFRTF?

A. While the Project is well aligned with the LFRTF combined alternative 3B-7B in regard to the transmission topology, one difference is that each transmission segment in the proposed Project is a double circuit line. The LFRTF, on the other hand, considered each transmission segment as single-circuit only.

VII. MAY VALLEY-LONGHORN EXTENSION

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

A. In this section of my Direct Testimony, I discuss the May Valley-Longhorn Extension that the Company is presenting to the Commission for consideration in this proceeding.

Q. PLEASE EXPLAIN WHAT THE MAY VALLEY-LONGHORN EXTENSION IS.

A. The May Valley-Longhorn Extension would be a 90-mile, 345 kV double circuit transmission line extension that would extend from the southeastern corner of the Pathway Project at the new May Valley Substation near Lamar, Colorado south to a new Longhorn substation, located near Vilas, Colorado. The Company is bringing forward this "May Valley-Longhorn Extension" for the Commission's consideration, as it would establish additional transmission interconnection opportunities for potential renewable generation developers in the wind-rich ERZ 3 in the southeastern area of the state. The Company anticipates that having a well-planned 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 gen-tie lines in this region to interconnect to the Pathway Project 345 kV transmission backbone. The May Valley-Longhorn Extension could also further enhance the geographic diversity of renewable energy resources, especially wind resources, that the Company could incorporate in its portfolio of bids presented in Phase II of the ERP, which can also present operational benefits as Company witness Mr. Hill explains further in his Direct Testimony.

Q. HAS THE COMPANY PREVIOUSLY CONSIDERED A TRANSMISSION LINE BETWEEN THE LAMAR AREA AND VILAS IN SOUTHEASTERN COLORADO?

A. Yes. This area of Colorado is identified as a wind-rich area and as such, the CCPG LFRTF study previously contemplated a line between the proposed May Valley Substation near the Lamar area, and the proposed Longhorn Substation near Vilas, Colorado.

Q. WHY IS THE COMPANY PRESENTING THE MAY VALLEY-LONGHORN EXTENSION IN THIS PROCEEDING?

A. The Company is aware of the rich wind resource area that is south of Lamar near Vilas, and to the extent the Commission approves the Company's CPCN for the Pathway Project, it is expected that wind resource bids in the 2021 ERP & CEP would also be proposed from this wind-rich area. The Company is presenting the option of extending the 345 kV transmission system to this area to provide a nearby interconnection point for potential wind resource bids. The Commission would have the option of determining that the May Valley-Longhorn Extension qualifies as a bid-eligible transmission option for the ERP Phase II competitive solicitation. Also, providing the Commission with CPCN information related to the May Valley-Longhorn Extension allows the Commission to consider the cost impact of utility-scale transmission access as compared to the transmission costs proposed by each wind bid for a gen-tie back to the new May Valley Substation.

Q. WHAT ARE THE BENEFITS OF DEVELOPING THE MAY VALLEY-LONGHORN EXTENSION?

A. As Company witnesses Ms. Trammell and Mr. Hill discuss, granting a CPCN for the May Valley-Longhorn Extension now will provide bidders with transmission certainty and enhance their ability to take advantage of federal tax credits if the line can be placed in service by 2025. From a Transmission Planning perspective, developing the May Valley-Longhorn Extension will help mitigate routing congestion from multiple gen-ties interconnecting at the May Valley Substation. As discussed in Company witness Ms. Rowe's Direct Testimony, the May Valley-Longhorn Extension will require a crossing of the Arkansas River south of Lamar, and designated lands, conservation areas, sensitive species habitat, and developed areas occur along the river corridor. By building this 345 kV extension, the Company would reduce impacts to these sensitive land uses/environmental resources by eliminating or minimizing the need for generators to construct multiple gen-ties across many of the land uses/environmental resources listed above.

Q. WHAT TRANSMISSION STUDIES HAS THE COMPANY CONDUCTED TO EVALUATE THE MAY VALLEY-LONGHORN EXTENSION?

A. Transmission power flow studies are not typical for evaluating the reliability of a radial facility as long as the proposed facilities meet good utility practices for engineering design. Here, the Company used good utility practices for the design and engineering done in sizing and scoping of the May Valley-Longhorn Extension.

Q. DOES THE COMPANY ANTICIPATE IT WILL NEED TO INSTALL ADDITIONAL TRANSMISSION INVESTMENT TO SUPPORT THE MAY VALLEY-LONGHORN EXTENSION BEYOND WHAT YOU HAVE IDENTIFIED ABOVE?

A. No. At this point in time, Public Service does not anticipate the need for additional voltage/reactive support, network upgrades, or interconnection costs above and beyond those already identified to support the May Valley-Longhorn Extension.

Q. DID THE COMPANY CONSIDER ANY ALTERNATIVES TO THE MAY VALLEY-LONGHORN EXTENSION?

A. The Company is presenting this as an option for Commission consideration. The alternative is to not advance the extension, and in this scenario, each generator will be responsible for their own transmission for interconnection at the new May Valley Substation.

Q. WHAT SPECIFICALLY IS THE COMPANY REQUESTING OF THE COMMISSION WITH RESPECT TO THE MAY VALLEY-LONGHORN EXTENSION?

A. The Company is recommending that the Commission consider issuing a CPCN for the May Valley-Longhorn Extension. In evaluating this extension, the question to the Commission is whether (1) Public Service should construct and own the 345 kV transmission extension between Lamar and the Vilas area; or (2) the developers should be required to include the necessary gen-tie to ultimately interconnect with the Pathway Project as part of any bids originating from this area.

VIII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend the Commission find that the Pathway Project is needed from a transmission planning perspective to support the Company's forthcoming 2021 ERP & CEP, and issue a CPCN for the Project. I additionally recommend the Commission consider the merits of the May Valley-Longhorn Extension, and if it determines there to be sufficient need and benefit at this time, similarly issue a CPCN for the May Valley-Longhorn Extension in this Application.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Statement of Qualifications

Amanda R. King

Ms. King is currently the Director of Strategic Transmission Planning in Xcel Energy's Electric Transmission organization. Her organization provides regional and local Transmission Planning, including production cost modeling for Public Service Company of Colorado and the other Xcel Energy operating companies. In addition, her organization works with the Regional Transmission Operators (RTOs) MISO and SPP. Prior to this position, Ms. King was the Manager of Regional Transmission Planning, and spent approximately 15 years as a Transmission Planning Engineer in Xcel Energy's Northern States Power footprint.

Ms. King has over 22 years of experience in the electric power industry as an Electrical Engineer, including not only Transmission Planning, but capital budget monitoring, strategic planning and management. She has provided strategic direction as well as engineering for a broad range of utility programs, projects, and studies including being the lead Transmission Planning engineer on one of the CapX 2020 345 kV Transmission line projects in the Midwest.

Ms. King holds a Bachelor of Science degree in Electrical Engineering from Iowa State University (1999).

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

**AFFIDAVIT OF AMANDA R. KING
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO**

I, Amanda R. King, 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 Minneapolis, Minnesota, this 2nd day of March, 2021.

Amanda R. King
Director, Strategic Planning

Subscribed and sworn to before me this 25th day of February, 2021.

Bonnie J. Anderson
Notary Public

My Commission expires 1-31-2024

BONNIE J. ANDERSON
Notary Public, State of Minnesota
My Commission Expires
January 31, 2024