2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN

PHASE II TRANSMISSION REPORT

PROCEEDING NO. 21A-0141E

SEPTEMBER 18, 2023

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I. INTRODUCTION

This Transmission Report provides a more detailed explanation of how Public Service Company of Colorado ("Public Service" or "Company") evaluated and identified transmission investments needed to support the Preferred Plan presented in the Company's 120-Day Report.

While the Company will continue to hone its transmission analysis and cost estimates, the diligence we put into the transmission component of this Transmission Report leads to two important takeaways. First, is our level of confidence in these cost estimates. We approached this Phase II transmission study process with the equally important objectives of transparency and continuous improvement through implementing our learnings from past ERPs and transmission planning efforts. The cost estimates provided in this Transmission Report do not rise to the level that the Company typically provides in CPCN applications, but our confidence level in the "transmission portfolio" identified in this Transmission Report is higher than past ERPs because of the Company's process improvements. This Transmission Report describes in detail how the Company developed the portfolio of transmission projects and cost estimates, while also providing insights into how key assumptions and variables could affect the final cost of transmission projects.

Second, our ground-up analysis, combined with the magnitude and location of generation resources contemplated in this resource planning cycle, and a variety of unexpected macroeconomic trends, leads to a total transmission portfolio that costs notably more than what we estimated at the outset of this proceeding. Specifically, the Company estimates the transmission portfolio needed to reliably implement the Preferred Portfolio will cost approximately $2.82 billion, including the Colorado's Power Pathway Project ("Pathway Project" or "CPP") - May Valley to Longhorn Extension ("May Valley-Longhorn" or "MVLE") but excluding the base cost of the Pathway Project and generator interconnection costs. We appreciate this estimate is significant. While the Company's transmission portfolio is tailored to its Preferred Plan, we fully expect that due to the magnitude and location of clean energy being acquired outside the Denver metro area, similar investment would be needed to support any of the Clean Energy Plan portfolios identified in the Company's 2021 ERP & CEP 120-Day Report.[1] As the location of electric generation sources change from within the Denver metro area to outside of it, the transmission system will see significant changes in its power flows, even to the extent that predominant flows may change. Because transmission planning cannot be

[1] In fact, the Company's transmission estimate for an ERP-only resource portfolio in the 120-Day Report only results in the deferral of approximately $600 million of transmission capital costs compared to the full transmission portfolio identified for the Preferred Plan, $250 million of which is attributed to the elimination of the MVLE.

conducted with perfect foresight of the evolution of the electric system, the Company's transmission system was not designed to meet these types of conditions and the Company must make significant investments to meet the needs of the energy transition. The single largest driver of transmission costs that would be needed to support any portfolio are extensive Denver metro area network upgrades, where siting, permitting, and the need for underground facilities are factors that drive complexity and cost.

As the Commission previously recognized in Decision No. C22-0559, Public Service "has little time prior to the 120-Day Report to definitively capture the projected transmission requirements for the various portfolios." Accordingly, the Commission directed the Company to "provide in the 120-Day Report transmission cost estimates at a similar level of specificity as the Company provided in the 120-Day Report for the 2016 ERP process," while also recognizing that Public Service "will likely need additive transmission studies after Phase II concludes to determine the full extent of the transmission investment necessary to implement a portfolio."[2] This Transmission Report provides background and context for the transmission cost estimate included in the 2021 ERP & CEP 120-Day Report. In preparing this Transmission Report, we developed project cost estimates using the Company's cost estimation process, experience from recent projects, and indicative cost estimate guides to inform our analysis while making adjustments to account for expected inflation and project risks.

Table 1 below provides the Company's transmission cost estimates by category of investment needed to support the Preferred Plan. As the Company discussed in Phase I of this proceeding, we expected transmission investments in support of the 2021 ERP & CEP would be needed in the following categories: (1) Denver Metro area upgrades, (2) grid (strength) reinforcement, (3) reactive/voltage support, and (4) generation interconnection facilities. With some adjustments to the categories shown in Table 1 (*i.e.* May Valley-Longhorn and San Luis Valley), these categories still broadly represent the transmission facilities that the Company has identified in support of the Preferred Plan.

Table 1 – Transmission Portfolio Cost Estimate by Category

Transmission Cost Category	Cost (millions)
May Valley – Longhorn Extension	$252
Transmission Network Upgrades, including both Denver metro and San Luis Valley areas	$2,322
Grid Strength Reinforcement and Reactive/Voltage Support	$250
Total	$2,820

[2] Decision No. C22-0559, at Para. 95 (mailed Sep. 21, 2022).

As described in Section III.B. of this Report, the generation interconnection costs developed for this 120-Day Report – approximately $123 million in capital costs – were developed in accordance with the bid evaluation procedures outlined in Phase I and were appropriate for purposes of selecting bids and creating portfolios. However, the Company's interconnection cost estimate was developed in a different manner than other transmission costs included in this Report given their upfront their use in the bid evaluation process, relying on publicly available interconnection studies instead of a detailed project scope development. As such, the Company anticipates that the actual costs that will be incurred in constructing these facilities will vary from this estimate.

While the Company’s identified transmission projects are needed to build out a robust system that minimizes transmission congestion, the scale of investment needed in the transmission cannot reasonably be deployed within the same timeframe as the generation resources in the Preferred Plan. The Company’s strategic vision for the Pathway Project created significant value by creating a transmission backbone on Colorado’s eastern plans to enable the Preferred Plan, but as we indicated in both Phase I and the Pathway Project proceeding, more investment in transmission is necessary to deliver the value of the Preferred Plan to our customers. Through the analysis discussed in this Transmission Report, the Company has developed a plan that prioritizes transmission projects as they are needed to resolve system constraints. The Company will maintain reliable service for customers as this transmission portfolio is constructed using operational tools such as generator curtailment and redispatch. The expeditious development of this transmission portfolio will allow the Company and our customers to realize the full value of the Preferred Plan.

In the following subsections, the Company presents a detailed discussion of the analysis it has undertaken to date to support the 2021 ERP & CEP 120-Day Report, along with the analysis and refinement that will continue to occur with respect to this transmission portfolio. First, we address the Company’s transmission planning process, technical analysis, and assumptions used to identify the Preferred Plan’s transmission needs. We identify the specific scenarios, sensitivities, and special considerations that were modeled as part of the Company’s 2021 ERP & CEP Phase II efforts. Second, we provide a detailed description of the Company’s process for estimating the costs of the transmission projects necessary to support the Preferred Plan. Third, we identify and describe the transmission projects the Company has identified consistent with the four categories of transmission investment identified in this proceeding and provide estimates for the costs of those projects. Last, we discuss the Company’s rigorous transmission project development and management processes that will guide the Company’s refinement and delivery of projects to support the Preferred Plan.

II. TRANSMISSION PLANNING

As the Company noted in the Pathway Project proceeding, Colorado's policies "do not aim to require utilities to seek transmission on a "just in time" or "just after need" basis."[3] The transmission planning process and the transmission projects identified in this Transmission Report were developed to carefully balance the needs of the Preferred Plan with an eye toward future system growth and the increasing difficulty of siting, permitting, and constructing large-scale transmission solutions in Colorado's population centers. From the Rush Creek Wind Project and Cheyenne Ridge Gen-Tie(s), to the 2016 Colorado Energy Plan and associated portfolio of transmission investment, to the 2020 Pathway Project, and now this 2021 ERP & CEP, Public Service has developed unique expertise in not only technically planning and studying what is needed to reliably transmit large quantities of dispersed, intermittent generation to the state's load centers, but also in executing large-scale transmission projects.

Public Service's Transmission Planning group is responsible for performing technical analyses of transmission system performance and capabilities, and develops transmission plans to fulfill various reliability, policy, strategic, and regulatory objectives.

A. PLANNING APPROACH

The Company's approach to transmission planning prioritizes the identification of cost-effective projects that prioritize the resiliency and reliability of the transmission network. Proposed transmission projects must accomplish the goal of relieving potential overloads as well as providing operational flexibility to account for unexpected outages and unique operational circumstances. Further, we seek to enhance value by seeking projects with multi-level benefits. If a transmission project can alleviate multiple violations at various locations, then that project is deemed to provide multiple benefits and is considered a preferred solution. We also consider the use of advanced transmission technologies ("ATT") and non-wire alternatives as potential solutions in whole or part.

Importantly, the planning approach that Public Service took in this Phase II process strives to transition our transmission system consistent with our evolving clean energy procurement and thus considers long-term system growth, typically on a multi-decadal timeline. This priority is particularly important in Colorado, where the Company's service territory has experienced and continues to experience significant load growth and state policies which increasingly prioritize the replacement of fossil-fuel end uses with a low carbon electric supply. Given the cost impacts of replacing assets early in their usable life, the Company avoids the development of minimum viable transmission projects that

[3] Proceeding No. 21A-0096E, Direct Testimony of Brooke A. Trammell, p. 32 lines 5-6.

are unable to accommodate expected future growth and instead prioritizes projects that strike a reasonable balance between short- and long-term system needs. This is done by evaluating the transmission project concepts on a long-term horizon using forecasted load growth assumptions. Seeking out projects that solve near-term transmission constraints, while also providing a reasonable level of increased capacity, allowing for future load growth, operational flexibility, and in turn provides better value to customers.

The Company identified transmission projects by evaluating transmission system performance across a range of scenarios. For each case analyzed, power flow contingency analysis results were produced for system performance criteria thermal and voltage violations during system intact (N-0) and single contingency event (N-1) analysis. The thermal violations represent the transmission capacity limiting facilities. Thermal (capacity) violations attributed to station equipment ratings are mitigated by replacing the limiting element(s) within the substation. Thermal (capacity) violations that are transmission line conductor rating limited are mitigated by reconductoring or rebuilding the line as applicable, or by identifying a transmission expansion alternative that mitigates multiple thermal violations by providing an additional transmission path in the network.

The Company does not expect that there are simple solutions to many of the constraints identified in its studies, but the scale of the challenge could potentially result in competitive advantages for the deployment of advanced technologies as transmission solutions. The Company's project alternative evaluations included a preliminary review of ATTs including both High Temperature, Low Sag ("HTLS") conductor types and other Grid Enhancing Technologies ("GETs"). The Company's study refinements will fully evaluate the appropriate alternative projects and technologies to gauge whether they can be implemented on Public Service's system and to ensure that the portfolio we construct delivers the value of the Preferred Plan to our customers in the most cost-efficient manner. While several of the projects identified in this Transmission Report are expected to employ HTLS conductors, the Company will more thoroughly evaluate the appropriate ATTs for each project in the study process described below. Consistent with the ATT-related terms of the Settlement Agreement approved by the Commission in Proceeding No. 21A-0096E, the Company will provide a detailed explanation of the ATTs considered for each project for which the Company seeks a CPCN.

B. TRANSMISSION NETWORK UPGRADES

As part of our Phase II analysis, the Company evaluated the transmission system to identify potential transmission network upgrade projects to deliver energy from the resources in the Preferred Plan. These network upgrades are critical to eliminating transmission constraints, allowing the Company to deliver clean energy to our customers while minimizing transmission-related renewable curtailments. While Company witness

Mr. Hari Singh's Phase I Direct Testimony initially addressed the need for transmission network upgrades within the Denver metro area, those needs have greatly expanded and this Phase II analysis identified a substantial magnitude of network upgrade projects within the San Luis Valley as well, given the competitiveness of bids and the size of the portfolios.

Consistent with industry leading practices, the Transmission Planning organization performed many power flow studies to assess the capability of the existing Public Service system to reliably accommodate the resources included in the Preferred Portfolio. The Company centered its Phase II Clean Energy Plan transmission study on several scenario analyses, with five scenarios categorized by year given the range of anticipated generation in-service dates (2025 Peak Demand, 2026 Peak Demand, 2027 Peak Demand, 2028 Peak Demand, 2030 Peak Demand), and three sensitivities (Twilight Sensitivity, Comanche Area Stress Sensitivity, Pathway Project Sensitivity), which are summarized in Table 2 below.

Table 2 – Transmission Planning Scenarios and Sensitivities

Scenario	Description
2025 Peak Demand	The 2025 case was evaluated to determine any immediate system needs not associated with the Clean Energy Plan. This analysis allowed for a benchmark of the system. The 2025 case reflects all planned projects, which are expected in 2025 as reported in the Company's FERC 890 Plan.
2026 Peak Demand	The 2026 case incrementally increases the load profile to align with the forecasted 2026 load reflected in the resource portfolio. The 2026 case reflects all planned projects, which are expected in 2026 as reported in the Company's FERC 890 Plan.
2027 Peak Demand	The 2027 case incrementally increases the load profile to align with the forecasted 2027 load reflected in the resource portfolio. The 2027 case reflects all planned projects, which are expected in 2027 as reported in the Company's FERC 890 Plan.
2028 Peak Demand	The 2028 case incrementally increases the load profile to align with the forecasted 2028 load reflected in the resource portfolio. The 2028 case reflects all planned projects, which are expected in 2028 as reported in the Company's FERC 890 Plan. .
2030 Peak Demand[4]	The 2030 case incrementally increases the load profile to align with the forecasted 2030 load reflected in the resource portfolio. The 2030 case reflects all planned projects, which are expected in 2030 as reported in the Company's FERC 890 Plan. Several sensitivities were applied to the 2030 case.
Twilight Sensitivity	This sensitivity contemplates a reduction of solar resources to reflect an early evening time of day where loads may still be reasonably high, combined with a severe drop in solar output. The sensitivity was applied to the 2030 peak demand case.
Comanche Area Stress Sensitivity	This sensitivity is designed to increase the power flow from the Pueblo, Colorado area to the Denver metro area. The sensitivity was applied to the 2030 peak demand case.
Pathway Project Stress Sensitivity	This sensitivity is designed to increase the generation along the new Pathway Project. The sensitivity was applied to the 2030 peak demand case.

[4] Unique to the 2030 Peak Demand case was an application of scenario sensitivities associated with changes in load and generator dispatch.

Each peak case above was dispatched with high solar resources, moderate wind resources, and moderate thermal resources. The Company's analysis also contemplates a fixed amount of load and does not include a variation of load changes. However, variations in generation dispatch can influence network flows, therefore future studies will determine the full extent of transmission investment that will be needed to reliably accommodate the new intermittent resources approved.

For the twilight evaluation of the 2030 case, solar generation is assumed to be near zero, moderate thermal resources, high storage output, and the remaining generation need was applied to the wind resources.

The Comanche stress case contemplates a regional evaluation of high output of resources near the Comanche substation. This stress is based on geographic location of resources rather than a particular fuel type. This case is meant to evaluate high flow from south to north on the 345kV network.

The Pathway Project Stress case contemplates an increase in renewable generation located on the Pathway regardless of fuel type. Given that the Pathway Project expands across the eastern portion of Colorado, the analysis is meant to determine any system constraints during high wind generation periods in eastern Colorado. The resources utilized for this dispatch were spread across the entire Pathway Project network.

For planning studies, Public Service adheres to NERC and Western Electricity Coordinating Council ("WECC") standards, in addition to Public Service's own Transmission Reliability Standards and Criteria.

In the following subsections, the Company describes how these scenario analyses were used to identify the initial network upgrades needed in both the Denver Metro Area and the San Luis Valley.

1. Denver Metro Area

The Company's transmission network is most complex in the Denver metro area due to the concentrated amount of load in and around the region. There are many connections among the different substations which provide reliability and support in the event of a transmission line outages. The step down or conversion to lower voltages that occurs at these substations is a critical element in how the transmission network provides service to our customers. The lower voltage network within the Denver metro area is fed from the Company's higher voltage network that is primarily responsible for delivering electricity from the Company's large-scale generators and remotely located renewable resources. As power is imported into the Denver metro area, this energy is largely moved on the higher voltage 230 kV system under normal system operations. However, under contingencies caused by transmission facility outages, that flow seeks a new path to the load and in some cases causes overloads on the underlying lower voltage system or on the transformers that link these systems. The interconnectivity of these systems increases the reliability and resilience of the transmission system as a whole, but also increases the vulnerability of the 115 kV system to overloads under standard planning assumptions and requires the expansion of those facilities to maintain that reliable and resilient operation.

The Company's analysis showed a number of new or compounded transmission challenges within the Denver metro area transmission network, for which we have identified a number of projects to address these challenges. Within the Denver metro area, transmission capacity constraints pose a significant challenge to taking full advantage of the environmental and economic benefits of the Preferred Plan, or any clean energy resource planning scenario, that would deliver significant amounts of new remotely located clean energy generation into the Denver metro area. The limitations in and around the Denver metro area are associated with limitations on both transmission line ratings as well as limiting elements within substations that can be rated less than the associated transmission line element.

The Company's portfolio of Denver metro upgrades is substantially larger than what was originally anticipated in the Phase I process, both in cost and in scope. The increased scope of the transmission portfolio presented in this Transmission Report is also driven by Public Service's planning approach that balances both present and reasonable future needs. While the smaller portfolio of transmission projects contemplated in Phase I may have alleviated transmission overloads within a short time window, the customer value of a smaller transmission portfolio would be quickly overwhelmed by additional load growth and resource acquisitions, requiring costly and difficult upgrades to new transmission facilities. Public Service's transmission portfolio proposed in this Transmission Report is effective in balancing these needs, and Public Service will continue to engage with stakeholders through the transmission planning process to refine and finalize studies of these projects. Increased costs are driven in part by the Company's robust project scoping and cost estimation processes that more accurately capture the nature of transmission upgrades necessary to alleviate congestion and overloads. Moreover, siting and permitting challenges, along with the need to underground many facilities in the Denver metro area are factors that drive the complexity and cost of these projects.

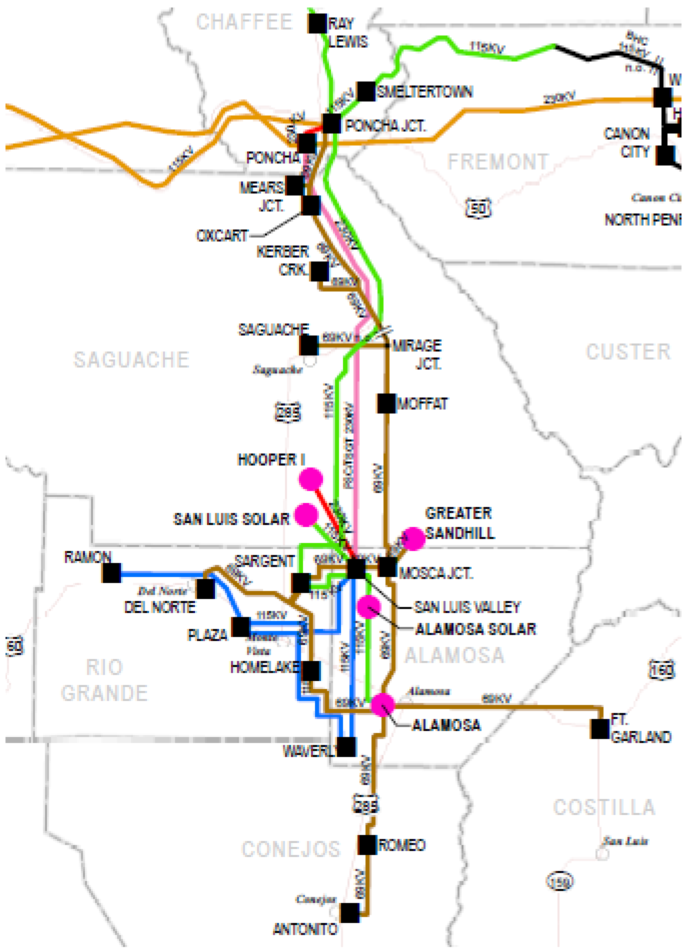
Based on results from previous transmission planning studies conducted by Public Service, the Denver metro area can be characterized as a load center with two major sources – the Daniels Park substation in the southern metro area and the Smoky Hill and Harvest Mile substation in the eastern metro area. These locations are significant in that they both have high voltage 345 kV transmission connections that are used to deliver generation from southern and eastern Colorado, respectively. As identified within the Company's transmission planning analysis of the Preferred Plan, these two substations remain the primary locations where power is converted from 345 kV to 230 kV before being delivered to the Denver metro load center. As power is transmitted from Daniels Park and Smoky Hill and the nearby Harvest Mile across the Denver metro area, as density increases, the local system has potential for overload conditions in both system intact (N-0) and under contingency (N-1) conditions with the additional generation. Through contingency analysis, the Company has determined that there is a mutual reliance between the existing eastern and southern 230 kV transmission network such that, in many cases, the loss of an eastern 230 kV path causes a transfer of flow onto the southern 230 kV network toward the Denver metro load center. The Greenwood – Denver Terminal 230 kV project developed and implemented in connection with the 2016 Colorado Energy Plan (Proceeding No. 20A-0063E) will alleviate overloads on the system driven by the Colorado Energy Plan, but will not be sufficient to support the Preferred Plan to the Denver metro area given the magnitude and location of renewable generation. The southern and eastern transmission network serves as a combined limiting constraint when delivering resources from the east and south to the load center in the Denver metro area. Though providing an increase in transmission capacity and reducing limiting constraints ultimately provides for an increase in flow, generation sources can also be useful in providing an opposing force against the transmission congestion which can allow for the increase in renewable imports from south and east of the Denver metro area. As central, northern and western generation is dispatched, the injected power essentially "pushes back" or provides counter flow against the southern and eastern paths helping to facilitate a more efficient use of the transmission system and in many cases alleviates the overload of some transmission elements. The closer the generation is to the load center, the more counterflow to the eastern and southern paths it will provide.

Two factors had significant influence on the scale of transmission investment needed in the Denver metro area. First, the scale and location of new generation that the Company is acquiring in the Preferred Plan (and other plans) results in increasing levels of load that is served by generation located in remote areas. Second, the level of investment is significantly influenced by the lack of cost-effective bids in the Denver metro area in the Phase II competitive solicitation. More specifically, planned generation retirements combined with the lack of bids for new or existing generation located within the Denver metro area transmission constraint, did not allow for the selection of resources within the Denver metro area to replace the departing generation. New projects within the Denver metro area constraint would have reduced the magnitude of transmission system work within the Denver metro area; however, projects did not materialize. The portfolio of Denver metro area transmission network upgrades resolves the challenges that arise in implementing the Preferred Plan by alleviating the constraints that arose from the natural progression of system expansion and generation changes. The Company's selection of Bid 0989, as discussed in the 120-Day Report, provides value to the transmission system in addressing Denver metro area constraint issues.

2. San Luis Valley Area

The San Luis Valley is a high-elevation mountain valley located in south-central Colorado with notable renewable energy development opportunity. The San Luis Valley is primarily bordered by the Sangre de Cristo Mountains on its eastern side and the San Juan Mountains to the west. Poncha Pass is the northernmost route in and out of the San Luis Valley, with the southern end of the Valley continuing into northern New Mexico. Retail electric service in the Valley is provided by Public Service and the San Luis Valley Rural Electric Cooperative, a member of Tri-State. Figure 1 below provides a schematic representation of transmission facilities in the San Luis Valley owned by both Public Service and Tri-State.

FIGURE 1 – Transmission Facilities in the San Luis Valley



There are three transmission lines that connect the San Luis Valley to Colorado's transmission grid. These three lines all begin in Poncha Springs in Chaffee County and enter the northern edge of the Valley over the 9,010-foot elevation Poncha Pass. Today, transmission configuration into the Valley is radial in nature – that is, the electric system in the Valley is connected to Colorado's electric grid at only one location (Poncha on the northern end). The three transmission facilities that connect into and out of the Valley are:

A 230 kV line jointly owned by Public Service and Tri-State from the Western Area Power Administration's ("WAPA") Poncha West Substation to the jointly owned Public Service and Tri-State San Luis Valley Substation (Circuit 3006). This line is operated and maintained by Tri-State.

A 115 kV line owned by Public Service from Public Service's Poncha Junction Substation to Public Service's Sargent Substation to the San Luis Valley Substation (Circuit 9811).

A 69 kV line owned by Public Service from the Poncha Junction Substation to Public Service's Mosca Junction substation (Circuit 6905). This line is used for local load serving purposes. This circuit has five intermediary 69 kV substations and supports the 69 kV radial feeds 6927 to Saguache and 6920 to Kerber Creek.

Not only does the San Luis Valley have existing system reliability needs due to the radial nature of the transmission system, but additional transmission capacity is needed to reliably integrate generation from this resource-rich area. Unfortunately, transmission development in and out of the San Luis Valley is incredibly challenging for a multitude of reasons. As Company witness Ms. Rowe explained in her Rebuttal Testimony in Proceeding No. 20A-0096E, and as the Company's initial comments in Proceeding No. 22M-0514E emphasized in detail, the area has rough, remote, and challenging geography and weather, significant permitting issues due to a patchwork of state and federal land use designations (conservation easements, US Forest Service-managed land, National Park managed lands, and multiple state-protected areas).

Notwithstanding the siting challenges within the San Luis Valley, joint efforts between Public Service and Tri-State have spanned nearly 25 years. One of the early efforts culminated in May 1997, when Tri-State, Public Service, and several other utilities issued a San Luis Valley High Voltage System Study Report through the Colorado Coordinated Planning Group ("CCPG"). This CCPG study report identified 14 critical contingencies in the San Luis Valley and identified 19 alternative solutions to address these contingencies. The study concluded that the transmission system was inadequate to serve future loads in the San Luis Valley and the transmission system in the Valley was at risk for voltage collapse leading to partial or total blackouts. The study also noted that while some of these challenges would be mitigated by the new Alamosa Terminal generating units coming online, this solution was insufficient to fully address reliability challenges in the San Luis Valley.

As noted above, since no additional transmission links to the Valley have been constructed in the last 25 years, the San Luis Valley transmission system reliability risks noted in the 1997 study continue to exist today. Although Tri-State has implemented an undervoltage load shedding scheme ("UVLS") as "safety net" to reduce the risk of voltage collapse, the outcome of this mitigation approach is partial loss of load instead of uncontrolled total load loss (i.e. blackout) in the Valley due to a transmission contingency. Using the quick-start combustion turbine ("CT") generating units at Alamosa, Public Service has adopted a different risk mitigation approach – proactively dispatching the Alamosa generation helps to reduce (but not alleviate) the load shedding risk during a scheduled/maintenance outage or a forced outage of the 230 kV or 115 kV transmission lines.

Together these two mitigation approaches have helped to reduce the risk of voltage collapse first identified in the 1997 study. However, until an additional transmission line connecting the San Luis Valley system to the broader Colorado transmission grid can be constructed and placed in-service, the unavailability of any one of these two mitigations would increase the risk of voltage collapse in the San Luis Valley. This risk becomes particularly higher for system operating conditions after twilight when all solar generation within the San Luis Valley ceases production and most load is served by importing power over the two transmission lines.

There has been renewed interest exploring and identifying new transmission solutions that would allow for increased exports from the San Luis Valley. In its Decision approving the Settlement Agreement filed in Proceeding No. 21A-0096E, the Commission agreed that it "is worthwhile to explore this issue," and subsequently opened a miscellaneous proceeding to explore transmission solutions for the San Luis Valley. At the same time, a CCPG San Luis Valley Subcommittee is actively studying potential transmission solutions and expects to issue a final report this fall. The Company continues to actively participate in the CCPG Subcommittee and may bring forward additional transmission recommendations to the Commission after the Subcommittee has completed its work.

In the meantime, the Company has identified a number of solutions as part of this Transmission Report that it expects to move forward with regardless of the outcome of the CCPG Subcommittee's work. For example, the continued availability of dispatchable generation, that is not time-limited in its operation, and is located in the San Luis Valley, remains an effective mitigation approach to manage the load-shedding and/or voltage collapse risk. As discussed in the 120-Day Report, the planned 2026 retirement of the existing Alamosa Combined Turbine ("CT") would leave no firm generation capable of providing this valuable risk mitigation service in the San Luis Valley. The Preferred Portfolio's selection of Bid 0986, a dispatchable natural gas bid, will allow the Company to maintain reliable electric service to customers in the San Luis Valley given existing transmission constraints and the difficulty of developing more robust transmission links into the San Luis Valley.

The Company has also identified several transmission projects that will enhance local system reliability and/or enhance our ability to export power from the San Luis Valley. One of these projects will bolster reliability of the existing 69 kV network in the San Luis Valley by removing limiting elements at substations and thereby increase the 69 kV network capacity. Another project for an additional (second) 115 kV transmission line from Alamosa to San Luis Valley will help mitigate the impacts of losing any single element on the existing 115 kV transmission line between these substations. Finally, enhancing the transmission capacity between Poncha Junction and Malta substations will enable power delivery from additional new resources in the San Luis Valley to loads outside of the San Luis Valley.

C. GRID STRENGTH REINFORCEMENT AND DYNAMIC REACTIVE/VOLTAGE SUPPORT

In addition to identifying projects that alleviate transmission constraints, the Company must also ensure that the transmission system is capable of operating in a reliable manner during a variety of generation dispatch and credible contingency scenarios. As described in Mr. Singh's Phase I Direct Testimony, the Company identified the potential need for projects that contribute to grid strength and dynamic reactive/voltage support.

Grid strength refers to the "stiffness" of the transmission system – higher stiffness is desirable because it results in better system stability performance. Grid strength is directly proportional to the magnitude of available short-circuit current and is highest closer to grid-synchronous generating stations because traditional generators produce significant amounts of short-circuit current. Grid strength decreases as distance from synchronous generators increases, so remote locations of the transmission system have relatively lower grid strength. As noted in Mr. Singh's Phase I Direct Testimony, low grid strength may be reinforced in some instances through the fine-tuning of inverter-based resources but may require the use of synchronous condensers.

To maintain a reliable network, voltages must be kept within certain ranges. Voltage changes on the transmission system buses are driven by multiple factors. Normal variability in magnitudes of generation and load lead to voltage fluctuations across the system. The flow of current through a transmission line can lead to higher or lower system voltage depending on the magnitude of the flow and the design of the line. Other aspects of grid operation also contribute to variability in bus voltages. Without proper attention to these and other contributing factors, bus voltages can go outside the limits established for system operation.

The Company is currently conducting studies that address concerns associated with both grid strength and reactive/voltage support, but preliminary results are not available within the timeline of Phase II of the 2021 ERP & CEP. As the portfolio of network upgrades is further defined, additional studies will be performed that examine system performance using more precise generator-specific data to refine the scope of grid strength and reactive/voltage projects needed for the reliable operation of the transmission system. In most cases, reactor banks, capacitor banks, or a combination of the two are projected to address voltage concerns. In some cases, studies may identify more specialized equipment (i.e. Series Capacitors, Static Synchronous Compensators ("StatComs"), and Synchronous Condensers) that are needed to resolve system challenges. The results of these studies will demonstrate which solutions are most helpful, where they should be located, and their appropriate size. As the transmission system evolves over time, the Company must periodically reexamine the system and reactive equipment in order to continue meeting system performance requirements. Transmission Planning evaluates the transmission system annually through NERC compliance which includes steady state and stability analysis.

The approved project scope for the Pathway Project included reactors and shunt capacitors to address system needs. The need, size, and locations of these devices were confirmed through the required studies. As described in Mr. Singh's Phase I Direct Testimony, the Company anticipates that additional grid strength and dynamic voltage/reactive support devices beyond those included in the scope of the Pathway Project will be necessary in support of the Preferred Plan. Rigorous technical analyses/studies using detailed, vendor-specific modeling data for wind, solar and battery-storage generating resources comprising the Preferred Plan will be required to confirm the final need, size and locations of these devices. Given the short timeframe for the analysis of transmission needs in Phase II of the 2021 ERP & CEP and the unavailability of this detailed generator-specific data until the interconnection process commences, the Company's analysis is ongoing and further refinements will be required before the scope of these projects can be identified with certainty.

The Company also plans to study system voltages in the Denver metro area, but the results of these studies are contingent upon the final scope of network upgrade projects. Once these projects have been finalized, the Company will determine the reactive and voltage support needs in the Denver metro area. Locations and sizes of any additional shunt capacitors or reactors will be determined by study and reviewed against constructability and cost minimization criteria. This analysis will allow the Company to develop a final portfolio of reactive and voltage support equipment needed in the Denver metro area.

D. IMPORT/EXPORT CAPABILITIES

The significant amount of variable generation resources contained in the Preferred Plan and the other portfolios this resource planning cycle will increase the value of transmission links with our neighboring utilities and neighboring regions. While projects that enhance Public Service's ability to import and export electricity generation are expected to provide additional value above and beyond what has been identified for the Preferred Plan, those capabilities are not necessary to support the Preferred Plan and are not included within project scopes and cost estimates provided within this Transmission Report. Public Service expects that it will continue to study and develop options to increase import and export capabilities in coordination with other utilities and regions to realize this additional value following the Commission's approval of a resource portfolio.

E. FERC-GOVERNED TRANSMISSION PLANNING PROCESSES

In addition to the already completed technical study work and planned refinements we have previously noted, Public Service will evaluate and refine its CEP transmission needs through a variety of FERC-governed processes.

To determine the full scope of interconnection facilities needed to support the Preferred Portfolio, Public Service will commence interconnection studies consistent with its OATT. Through these processes, Public Service thoroughly vet transmission projects and consider project alternatives, including potential applications for ATTs. These studies are complex in nature and may affect the timeline for the development of transmission solutions.

For the interconnection of new resources, generators and the Company will follow applicable Large Generator Interconnection Process contained within Attachment N of Xcel Energy's Open Access Transmission Tariff ("OATT"). Generators that have not already entered Public Service's interconnection queue by requesting interconnection service will be submitted for study through a Resource Solicitation Cluster. Due to the timelines associated with the LGIP, generators with earlier in-service dates are likely to be studied as Provisional Interconnection requests to ensure that in-service dates can be met. Provisional Interconnection studies are done in parallel with the full, queued procedure and studies, and result in the ability to interconnect, but do not result in construction of transmission network upgrades beyond the substation at the point of interconnection. Provisional interconnection agreements may result in granting a reduced amount of interconnection service prior to network upgrades identified by the full interconnection study being placed into service.

Transmission network upgrades will also be identified through studies for both generator interconnection requests and requests for firm transmission service under the Xcel Energy OATT. While interconnection studies may identify network upgrades for interconnection service, it is the network upgrades identified for granting transmission service that enable the generator's output to be delivered to customers. To qualify the resources acquired through the 2021 ERP & CEP as Designated Network Resources ("DNRs") to serve Network Load, or Public Service's retail customers, Public Service will request Network Integration Transmission Service ("NITS") for all generators pursuant to its OATT.

Finally, in addition to study processes driven by interconnection and transmission service requests, Public Service will continue to engage in its coordinated transmission planning activities pursuant to Xcel Energy's OATT. This will include an array of stakeholder-driven local transmission planning to identify and evaluate needed transmission solutions. Stakeholder engagement in transmission planning will occur through applicable forums such as the Company's recurring FERC Order 890 meetings or the CCPG stakeholder process.

III. PROJECT SCOPE AND COST ESTIMATE DEVELOPMENT

Following the completion of the transmission planning studies that identified system constraints and developed solutions, the Company conducted a tabletop analysis of those projects in order to identify preliminary project scopes, determine the feasibility of the projects, make early adjustments or refinements to project scopes as needed, identify and account for potential project risks that could be encountered in the development of each transmission project, and develop preliminary cost estimates for projects.

A. DEFINING PROJECT SCOPE

In order to improve the quality of the Company's estimated costs and in-service dates that are provided in Phase II of the 2021 ERP & CEP, the Company developed preliminary scopes for each project, addressing relevant engineering, materials, labor, siting and permitting, and land acquisition aspects that may be needed to support each of the identified transmission projects. This early-stage project scoping allows the Company to account for significant project components and develop more accurate early-stage project descriptions and, ultimately, cost estimates.

Using the transmission planning study results, the Company's Transmission Engineering team reviewed the ampacity requirements and any limiting elements in the system. For substation projects, the team conducted a holistic review of each impacted substation and developed a project scope accordingly. The Company's tabletop analysis included an evaluation of siting, permitting, and land rights acquisition needed for each project scope. Siting and permitting processes were accounted for in project schedules based on the Company's experience with similar projects and in the jurisdictions where projects are located. The need for new or expanded substation sites, transmission line right-of-way, or other land rights acquisition were considered for project scopes that included new transmission facilities not located on property already owned by Public Service or that cannot be located in existing easements held by the Company. The Company's assumptions regarding land rights acquisitions will inherently evolve as project scopes are further developed and as available space at the Company's facilities and space needed for each project is assessed during project development.

Projects located at existing Company facilities were screened against facility general arrangement diagrams to evaluate the feasibility of making necessary installations and expansions at those facilities. If that evaluation identified that a project was not feasible as initially developed, the Company adjusted the planned project to account for project scope expansions. By validating project scopes at this level, the Company's process reduces but does not eliminate the risk that the projects identified in this Transmission

Report will require major scope expansions in order to meet the identified planning need. However, because the analysis of substation projects was based on general arrangement diagrams and did not include site visits, there is a potential for substation upgrade projects to expand in scope as project development proceeds.

The Company evaluated all transmission line projects to develop the project scope necessary to meet Transmission Planning's identified project need. Where a Planning need was identified to increase the rating of an existing transmission line, the Company evaluated whether the higher rating could be achieved using an alternative conductor of the same size. For all transmission line projects where this could be accomplished, the Company developed a project scope to reconductor the existing transmission line. These projects did not include an analysis of the age or condition of the existing facilities, so there is the potential for the scope of these projects to expand or change as project development proceeds. If the Company could not achieve the identified line rating with a conductor of the same or smaller size than the existing conductor used on a transmission line, project scopes were developed for the transmission line to be rebuilt. For new transmission line projects, the Company's engineers and siting experts applied their judgment regarding transmission line siting, length, and the ability to construct overhead versus underground.

Based on recent experience with transmission development, the Company anticipates risk to on-time completion of these projects because of the size and complexity of the transmission portfolio; construction sequencing and scheduling; local siting challenges and permitting timelines; land availability; supply chain constraints for transmission equipment, such as conductor, transformers, electrical equipment, and power electronic devices; and labor constraints from competing projects. In some cases, the Company may be required to adjust project scopes to account for equipment availability, siting challenges, or other factors that could not be included in the preliminary studies. Although it cannot be ascertained at this time which projects in the transmission portfolio may not meet their anticipated in-service dates, project delays are likely to impact system dispatch and operations, resulting in increased curtailments until the full transmission portfolio can be completed.

B. PROJECT COST ESTIMATION

In this section, the Company details its process for cost estimation for the categories of transmission cost estimates provided in this Transmission Report.

1. Network Upgrade Projects

As described above, the Company has developed and implemented a more robust cost estimation process for the transmission projects identified in this Transmission Report compared to previous ERP transmission cost estimates. While this process provides us with a greater level of confidence in the cost and schedule estimates contained in this Transmission Report relative to previous ERP processes, these estimates are indicative and will be further refined as the Company completes transmission planning studies and refines project scopes during the development of these projects.

The project cost estimates presented in this Transmission Report were developed from the project scopes identified in the feasibility evaluation and are informed by the project risks identified during the Company's preliminary project analysis. Once project scopes were determined, the Transmission Engineering team developed an indicative estimate of the cost of engineering, procurement, and construction for each project. Estimates were developed for each project based on present-day costs and then adjusted to account for the anticipated in-service date and the Company's recent experience with inflation on labor, materials, and land costs for transmission projects. Given the early stage of development discrete risk reserves were not calculated and the Company accounted for risk through more general contingency assumptions that are included within the cost estimate provided for each project.

As projects are confirmed or modified through further study, the Company will follow its cost estimation procedures to refine the cost estimates developed for these projects as detailed in Section V.B. below. Updated project cost estimates and refined or modified project scopes will be presented to the Commission through the appropriate forum going forward (for example, through CPCN or Rule 3206 filings).

2. Grid Strength Reinforcement and Dynamic Reactive/Voltage Support

Given that the Company's analysis of grid strength reinforcement and dynamic reactive/voltage support needs is still ongoing, the Company's cost estimate for these categories of transmission investments is based on and remains consistent with the high end of the range of costs discussed in Mr. Singh's Phase I Direct Testimony. However, the Company notes that costs for StatCom and Synchronous Condenser devices have been steadily increasing and are currently experiencing lead times of three to four years. The Company identified the installed cost of a StatCom device as approximately $50 million, however, StatCom device costs have increased since the Company's Phase I filing to approximately $50 million without accounting for installation or other site-specific costs. Synchronous Condensers were identified as costing approximately $52 million in Phase I testimony for facility procurement, installation, in-servicing costs, and other expenses, however, recent price quotes that the Company has obtained for Synchronous Condenser devices have totaled approximately $90 million without accounting for additional installation or in-servicing costs. The Company's ongoing analyses of Grid Strength and Reactive/Voltage Support needs will result in the development of more accurate cost estimates which will be presented to the Commission in the appropriate forum, such as an application for a CPCN.

3. Generator Interconnection Facilities

As part of the Phase II competitive solicitation, bidders were asked to provide initial interconnection cost estimates within each separate bid proposal including the source or basis for the estimate. In order to ensure fairness in the relative comparison of each bid that the Company received, the Company's Transmission Access reviewed the reasonableness of the bidder provided estimates group using publicly available generator interconnection study information.

Generator interconnection costs presented within this Transmission Report were developed in accordance with the bid evaluation procedures outlined in Phase I and are appropriate for purposes of selecting bids and creating portfolios. However, the Company anticipates the actual costs that will be incurred in constructing these facilities will vary. The time allowed for development of these costs in the Phase II bid evaluation does not provide for the development of a detailed project scope that accounts for the unique facilities that are required for the interconnection of each generator. Additionally, even if time allowed, the development of detailed information for bid comparison would carry a significant cost that would not be justified as only a small fraction of the bids analyzed would actually proceed through approvals and into construction. In reviewing interconnection cost estimates for reasonableness, an adjustment was made by the Transmission Access group consistent with the publicly available cost information as to interconnection location, voltage, and nameplate capacity – which resulted in an adjustment to the bid price where warranted. The interconnection cost data provided in Section IV.D. reflects these adjusted bid comparison costs.

The Company relied on interconnection cost information from Definitive Interconnection System Impact Study ("DISIS") studies that were completed in 2022 and 2023 and developed a set of standardized interconnection costs that were applied to projects of a similar nature and location, for example, based on the voltage level of an interconnection at an existing substation or the construction of a new switching station. Transmission network upgrade costs are not factored into bid comparisons as these costs address the cumulative system impact of the aggregate bids comprising the Preferred Plan and do not affect individual bid pricing.

As interconnection costs presented in this Transmission Report are based on publicly available historical information, the costs have not been adjusted for inflation based on the projected in-service date of each facility, or for recognition of the current limited availability, long lead times, and significant cost increases for specialized electrical equipment. The Company will develop refined interconnection cost estimates for resources selected in this Phase II solicitation as part of its FERC-governed interconnection process set forth in the Large Generator Interconnection Process ("LGIP") contained in Attachment N to Xcel Energy's OATT. Updated, refined interconnection cost estimates based on the project-specific analysis conducted in the LGIP will be provided to the Commission in the appropriate forum, such as annual Rule 3206 Reports and/or CPCNs filed pursuant to Commission Rules 3102 and 3206.

IV. IDENTIFIED TRANSMISSION PROJECTS AND COST ESTIMATES

In this section, the Company provides details of the transmission projects identified as needed to support the Preferred Plan, including the May Valley – Longhorn Extension, network upgrades, grid strength and voltage/reactive support facilities, and generator interconnection facilities. As the Company has previously mentioned, while these projects were developed with an eye specifically on the Preferred Plan, a comparable scale of projects to transition the transmission system would be anticipated for the other portfolios discussed in the report or for any plan with a large increase in clean energy acquisitions.

A. COLORADO'S POWER PATHWAY PROJECT: MAY VALLEY – LONGHORN EXTENSION

In Proceeding No. 21A-0096E, the Commission approved a settlement agreement ("Pathway Project Settlement Agreement") that granted the Company a Conditional CPCN for the MVLE portion of the Colorado's Power Pathway Project, pending the outcome of the Phase II resource solicitation in the 2021 ERP & CEP.

Consistent with Paragraphs 371-373 of the Phase I Decision, the Company allowed bidders to structure bids assuming that the MVLE is constructed and assuming it is not. The Company did not require separate bid fees for bidders that proposed mutually exclusive alternative bids for the same project (e.g., same project owner, location, technology, and size) that interconnect to the MVLE or that interconnect elsewhere on the transmission system.

Accordingly, the Phase II decision in this Proceeding is limited to determining whether the generation projects seeking to interconnect to the MVLE are part of a cost-effective resource plan, when the total cost of the MVLE is included.[5] As demonstrated in Section 2.5 of the 120-Day Report, the Company's analysis shows that the Preferred Plan, including the costs of the MVLE, is a lower-cost plan than if the Company were to not construct the MVLE.

Following the Commission's conditional approval of the MVLE, the Company completed a routing study and public/stakeholder outreach in June 2022, and acquired easement options to preserve a viable route for the MVLE, but otherwise paused work on the MVLE pending resolution of the Phase II Resource Solicitation. In support of the inclusion of the MVLE in the Preferred Plan, the Company has developed updated cost estimates and project timelines for the MVLE. The updated cost estimate for the MVLE is approximately

[5] Decision No. C22-0459, at ¶ 373.

$250 million[6] and the Company is planning to place the MVLE in service on October 31, 2026.

The Pathway Project Settlement Agreement requires the Company to make a filing with the Commission in Proceeding No. 21A-0096E within 14 days of the final Phase II decision in this proceeding that sets forth the updated cost estimates and timelines for the MVLE, at which point the approval of the MVLE would become an unconditional CPCN. Consistent with Decision No. C22-0270, the Company will provide additional cost detail and address the Commission's directives concerning a Performance Incentive Mechanism for the MVLE through appropriate filing(s) in Proceeding No. 21A-0096E.

B. TRANSMISSION NETWORK UPGRADES

The Company has identified a portfolio of 25 transmission network upgrade projects to support the Preferred Plan that are primarily centered around the Denver metro area and the San Luis Valley. In aggregate, these network upgrade projects are anticipated to cost approximately $2.32 billion. These projects include substation upgrades and expansions including the replacement or installation of additional transformers, the construction of new substations, the reconductoring or reconstruction of existing transmission lines, and the construction of new transmission lines. Additional information regarding these projects is provided in Appendix 1 at the end of this Transmission Report, including project descriptions, locations, anticipated ISD, and cost estimates.

C. GRID STRENGTH REINFORCEMENT AND DYNAMIC REACTIVE/VOLTAGE SUPPORT

As noted in Section III. above, the Company's initial evaluation of grid strength and reactive/voltage support facilities necessary to enable the Preferred Plan is currently underway and study results will be dependent on generator-specific data that is not currently available. The Company's Phase I analysis for these two categories of transmission projects identified the potential need for two 345 kV, 550 MVA Synchronous Condensers and one to two 345 kV, +/- 200 MVAr StatComs, in addition to the "base" level of shunt reactive devices that were included within the scope of the Pathway Project.

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[6] The updated cost estimate includes environmental mitigation costs associated with the listing of the Lesser Prairie Chicken ("LCP") under the Endangered Species Act. These costs were not included within the Company's original estimate for the MVLE provided in the Direct Testimony of Brian J. Richter in Proceeding No. 21A-0096E given the status of LCP issues as of that filing. The Company will provide additional information about these environmental compliance costs in the filing made in Proceeding No. 21A-0096E 14 days after the Commission's final Phase II decision in the 2021 ERP & CEP.

In Mr. Singh's Phase I Direct Testimony, the Company provided a combined preliminary cost estimate for these categories of $150 to $250 million. Pending the completion of further study, the Company currently anticipates that grid strength and reactive/voltage support project costs of approximately $250 million based on the analysis conducted in Phase I.

D. INTERCONNECTION FACILITIES

Table 3 below lists the net present value of interconnection costs that were used for bid comparison purposes in Phase II of the 2021 ERP & CEP. As noted above, these will be subject to further review and refinement as the formal FERC-established interconnection process moves forward for each project.

Table 3 – Modeled NPV of Interconnection Costs

Portfolio: 1 - Preferred Plan (SCC)

Bid_ID	NPV Trx PO-PF Interconnection Costs ($)
-	[redacted]
1000	
0989	
0986	
1002	
0218	
0151	
1125	
1010	
1006	
0476	
0149	
0589	
0249	
0251	
1026	
1029	
1015	
0045	
1012	
0295	
0044	
Sub-Total	$ 65,470,712

New Substation	Bid_IDs	NPV Sub Pool Cost ($)
Comanche 230kV	0218	[redacted]
Missile	0151	
Alamosa	1125,0149	
	Sub-Total	$ 64,420,795
NPV Trx PO-PF Interconnection Costs ($)		$ 129,891,507

V. TRANSMISSION PROJECT MANAGEMENT AND EXECUTION

The Company's transmission project management processes, described in this section, provide the framework through which Public Service will responsibly execute the transmission projects necessary to support the Preferred Plan.

A. TRANSMISSION PROJECT DEVELOPMENT AND MANAGEMENT

Public Service will manage the development, engineering, and construction of transmission projects through its Project Life Cycle ("PLC"). The Company's Integrated System Planning ("ISP") and Transmission Project Management ("TPM") groups are responsible for managing the PLC process to develop, monitor, and control project scope, estimates/budget, schedule, and risks. The PLC provides clear directions for each stage and approvals at each gate for all phases of the development of transmission capital projects – after project origination through planning, budget creation, financial approval, real estate acquisition, design, construction, commissioning, and closeout. Through the PLC, the ISP is responsible for coordinating the Company's groups that contribute to the identification and planning of projects including transmission planning, siting and land rights, procurement, and construction. ISP identifies and evaluates the need for a project and coordinates the development of a comprehensive project scope and estimated cost. Once a project scope and estimate has been sufficiently developed by the ISP group and receives governance approval at the appropriate level within the Company as well as necessary regulatory approvals, the Transmission Project Management ("TPM") group is responsible for project execution and delivery. The PLC process is intended to ensure that the Company diligently and prudently constructs needed transmission facilities with clearly defined processes and robust oversight.

The Company's PLC includes seven specific stages: (1) project origination, (2) budget estimate package, (3) project budget approval, (4) project development, (5) engineering, (6) construction, and (7) project closeout. In order to move forward to the next stage, each project must go through a "gate" approval in which the project is reviewed within the context of the PLC requirements and a further decision is made as to whether or not to authorize the next stage of a project.

Projects managed through the PLC are classified into one of three tiers in order to match the level of rigor that project teams apply to each project based on general size and complexity. Tier classifications are dependent on the project's cost, significance and public impact, complexity, and environmental impact. Tier classifications determine the level of scrutiny for each project and ensure that the resources expended to manage a project through the PLC are commensurate with each project's needs. Tier classifications for projects also dictate the required reviews and approvals as projects progress through the stages and receive gate approvals.

B. COST ESTIMATE DEVELOPMENT

Within the PLC, the Company develops several cost estimates during the life of a transmission project. The level of accuracy of a cost estimate is determined by the progress towards project completion. To generate these estimates, the Company uses a well-regarded software tool for developing cost estimates called InEight Estimate. Company engineers use InEight Estimate to develop detailed cost estimates by entering historical cost data and other relevant information into the program, which then calculates a cost estimate using those inputs. InEight Estimate provides a framework to organize extensive cost component reference data, assemble estimates, manage multiple versions of the cost estimate calculation, and generate summary and detail reports for a variety of project types. The user builds their own database of components and activities suitable to their projects and populates and maintains the unit prices and other factors. The Company uses this tool in developing cost estimates for its transmission line and substation projects.

The Company typically identifies four classifications of project estimates that may subsequently be generated for each transmission project: Indicative, Scoping, Appropriations, and Engineering Estimates. An Indicative Estimate carries no defined or implied level of accuracy and is based upon the initial understanding of the project and the estimator's experience, it is not developed for every project. It is typically an informal communication generally used for high-level alternative project comparisons and discussion. A Scoping Estimate is produced before engineering design and siting and land rights activities have begun or are only approximately 5 percent complete. Scoping-level estimates are typically used by the Company as part of the Applications for CPCNs filed with the Commission given the regulatory timing and processes around developing and processing a case at the Commission which occurs over many months. The next level of estimate, an Appropriations Estimate, refines a previously produced Scoping Estimate and improves the level of accuracy for budget and forecast purposes. It will be based on conditions expected to be encountered on the specific construction project and should include a site visit. The engineering and design work may be approximately 5-25 percent complete; the land acquisition work should generally be approximately 5-25 percent complete, while permitting and siting work should be approximately 60-80 percent complete. Finally, the most accurate level of estimate that the Company develops is an Engineering Estimate, which includes the best material and equipment information available. Permitting, siting, and land acquisition work should be approximately 80-100 percent complete. The engineering should be approximately 75-100 percent complete;

material costs are usually known with certainty; materials with long lead time items are usually ordered. At the Engineering Estimate stage, construction costs are still unknown, and remaining risks may still be accounted for in the project's cost estimate.

Within the PLC, an Indicative Estimate is developed in Stage 1, a Scoping Estimate is developed at Stage 2, an Appropriation Estimate is developed at Stage 4, and an Engineering Estimate is developed at Stage 5.

While the Company has developed indicative estimates for transmission projects in this Transmission Report and has previously provided indicative estimates and early-stage project scopes to the Commission in other forums, the Company's current practice is to present project scopes estimated project costs for Commission determination or approval, through annual Rule 3206 Reports and required CPCN applications, once a project has reached Stage-Gate 3 approval. This is the point in the PLC at which the Company considers a project to be sufficiently defined and to have received sufficient internal approval to seek regulatory approval. Once a project has received Stage-Gate 3 approval, material changes to the scope, cost, or schedule of the project require additional internal oversight and approval. The level of authority needed to approve changes to a project past Stage-Gate 3 is dependent on the impact that the change has on the project scope, schedule and cost.

C. PROJECT RISK IDENTIFICATION AND MANAGEMENT

Risk identification and management is a key component of prudent project management, and the Company's management of transmission projects accounts for ways in which the final spend on a project many months and often several years in advance of completion is ultimately unknown. While the Company has historically included a contingency as part of a transmission project cost estimate when applying for a CPCN, the Company no longer develops cost estimates that include set percentages above and below the stated cost estimate to account for the uncertainty associated with the development and construction of its transmission cost estimates. The Company's cost estimation process now more granularly accounts for uncertainties through the development of a risk reserve forecast. While the Company is unable to develop this information within the time constraints for its preliminary analysis in the Phase II process, each refined cost estimate that the Company presents in an application for a CPCN includes a project-specific risk reserve for categories of costs where necessary expenditures may increase if a risk event occurs. The types of risk events that the Company may account for when developing the risk reserve forecast include, among other issues, construction delays (which may be related to, among other things, supply or transport issues, hindrances encountered on the land, access to roads, or local jurisdiction permitting issues), problems with material supplies (including delivery timing, quality issues, or unanticipated equipment failure), fluctuations in prices of equipment (which may related to international tariffs, commodity price changes, and industry demand), weather-related delays or issues, licensing and permitting issues unique to the location (such as railroad licenses or jurisdictionally-mandated mitigation requirements), or changes in project scope due to other circumstances. The risk reserve reflects an assigned cost component for those anticipated risks at the time of cost estimation. A specific risk reserve amount is based on the estimated cost to incur the risk event and the probability of the risk event occurring. The risk reserve amount is typically determined based on a qualitative and quantitative evaluation of the activities and plans for the project, using the Company's engineers' experience with similar projects or project components. The use of a risk reserve within refined cost estimates allows the Company to account for unknowns with some granularity for specific identified risks, based on the amount of engineering, siting and land rights activities, and other work the Company has completed at the time the cost estimate is developed.

The PLC provides a framework for project execution. The project team must create required deliverables in each stage to satisfy the gate approval requirements. Internal gate approvals provide a venue for awareness and oversight. Through internal oversight and approval, personnel from all levels of the Company have input and oversight to the project development and execution plan. This structured collaboration enables safe, reliable, and responsible project execution.

APPENDIX 1: NETWORK UPGRADE PROJECT LIST

1. Greenwood Substation Bus Tie Uprate	
Project Description:	Replace several limiting elements on the 230 kV bus to achieve a 2000-amp rating.
Project Location:	Arapahoe County
Anticipated ISD:	2026
Cost Estimate:	$1.7M

2. Arapahoe 115 kV Bus Uprate and Second 230/115 kV Transformer	
Project Description:	Replace all limiting elements on the 115 kV bus to achieve a 2000-amp rating. Install a new 280 MVA 230/115kV transformer and associated equipment to connect the transformer within the yard.
Project Location:	City and County of Denver
Anticipated ISD:	2028
Cost Estimate:	$28.7M

3. Chambers Third 230/115 kV Transformer	
Project Description:	Install a 3rd 280 MVA 230/115 kV transformer at the Chambers substation. As there is no room to complete this project at the existing Chambers substation, the project assumes the construction of a new substation near the Chambers substation. The new substation will be 230/115 kV and house all three 230/115 kV transformers. The existing Chambers substation will house the 115 kV yard. The new substation near Chambers also allows for additional connections needed on other identified projects.
Project Location:	Adams County
Anticipated ISD:	2029
Cost Estimate:	$101.3M

4. Daniels Park to Greenwood Circuit 5707 Uprate	
Project Description:	Reconductor 8.4 miles of circuit 5707 to achieve a 756 MVA rating. Replace substation elements that do not meet the required rating. This project is expected to use HTLS conductor.
Project Location:	Arapahoe and Douglas Counties
Anticipated ISD:	2026
Cost Estimate:	$12.9M

5. Daniels Park to Greenwood Circuit 5111 Uprate	
Project Description:	Reconductor 8.4 miles of circuit 5111 to achieve a 756 MVA rating. Replace substation elements that do not meet the required rating. This project is expected to use HTLS conductor.
Project Location:	Arapahoe and Douglas Counties
Anticipated ISD:	2026
Cost Estimate:	$11.9M

6. Phase Shifting Transformer on Missile Site to Daniels Park 345 kV Circuit 7109	
Project Description:	Install a 345 kV 650 MVA +/ 60 degrees phase shifting transformer in a new station near Missile Site along the 7109 right of way. Install required transmission line to connect to the new station.
Project Location:	Arapahoe County
Anticipated ISD:	2030
Cost Estimate:	$137.7M

7. 230 kV Circuit 5165 In and Out of Harvest Mile	
Project Description:	Bring 230 kV circuit 5165 in and out of the existing Harvest Mile Substation. Install 230 kV equipment within the existing Harvest Mile Substation to connect the new circuit. Based on routing congestion between the existing 5165 circuit and Harvest Mile Substation it is assumed that this in and out connection will be underground.
Project Location:	Arapahoe County
Anticipated ISD:	2027
Cost Estimate:	$41.5M

8. New Double Circuit 230 kV Line from Harvest Mile – Chambers – Sandown – Cherokee	
Project Description:	Install a new double circuit 230 kV line with a required rating of 3000 amps on each circuit. For estimating purposes, the Company assumed 8 miles of overhead construction and 19.3 miles of underground construction. The planning study indicated that these circuits should be constructed as 345 kV capable. For the overhead section, the Company assumed structures similar to the Pathway Project would be used. For the underground section, the Company assumed that during 230 kV operation both circuits will be located in a single duct bank. Should future conversion to 345 kV operation be required, an additional duct bank would be installed at that time and is not included in the Company's estimate. For the substations the Company assumed an expansion/new location will be required at Harvest Mile to fit the 230 kV connections. As discussed for the Chambers Third 230/115 kV Transformer project, a new 230 kV substation near Chambers is already contemplated and is also required for this project. At Sandown there is currently no 230 kV equipment or space for expansion, so the Company assumed that a new station will be required near Sandown for the 230 kV connections. At Cherokee station there is space within the existing yard to build out the facilities required to connect the new lines.
Project Location:	City and County of Denver, Arapahoe, and Adams Counties
Anticipated ISD:	2030
Cost Estimate:	$1.4B

9. Uprate Substations on Circuit 9811	
Project Description:	Replace 115 kV limiting elements at Poncha Junction and San Luis Valley Substations to achieve facility ratings equal to the 1250-amp line conductor rating .
Project Location:	Chaffee County
Anticipated ISD:	2025
Cost Estimate:	$3.9M

10. Uprate Substations on Circuit 3006	
Project Description:	Replace 230 kV limiting elements at Poncha West and San Luis Valley Substations to achieve a 1200-amp rating. This project will require coordination with Western Area Power Authority and Tri-State G&T as the terminal owners.
Project Location:	Alamosa and Chaffee Counties
Anticipated ISD:	2025
Cost Estimate:	$6.5M

11. Tollgate Substation Load Shift	
Project Description:	Move the 230 kV Tollgate Substation source from circuit 5285 to circuit 5167. Replace limiting elements at each substation on circuit 5285 to achieve a 1266-amp rating.
Project Location:	Arapahoe County
Anticipated ISD:	2026
Cost Estimate:	$12.9M

12. Uprate Substations on Circuit 5057	
Project Description:	Replace 230 kV limiting elements at Cherokee and Lacombe Substations to achieve a 2200-amp rating.
Project Location:	Adams County and City and County of Denver
Anticipated ISD:	2028
Cost Estimate:	$7.9M

13. Havana to Chambers Circuits 9543 and 9544 Uprate	
Project Description:	Rebuild 115 kV circuits 9543 and 9544 between Havana and Chambers substations to achieve a 1600-amp rating. Consideration was given to reconductoring both circuits. The existing lattice towers are not able to support a large enough conductor to meet the required rating. Replace limiting elements at Havana Substation to meet the 1600-amp requirement.
Project Location:	Adams County and City and County of Denver
Anticipated ISD:	2027
Cost Estimate:	$18.2M

14. Malta to Poncha Junction Circuit 9255 Uprate	
Project Description:	Rebuild 32 miles of 115 kV circuit 9255 between Poncha Junction and Otero Tap Substations to achieve a 1200-amp rating. The section between Otero Tap and Malta Substations will have already achieved this rating by completion of an existing project. For the rebuilt section, rebuild the structures to be 230 kV capable. Replace limiting elements at Malta Substation and Poncha to achieve the required rating.
Project Location:	Chaffee County
Anticipated ISD:	2028
Cost Estimate:	$71M

15. Daniels Park Fourth Transformer	
Project Description:	Install a 4th 560 MVA 345/230 kV transformer at Daniels Park Substation. This installation may require the acquisition of additional land. Currently, land surrounding the Daniels Park substation is designated as open space.
Project Location:	Arapahoe County
Anticipated ISD:	2029
Cost Estimate:	$56.8M

16. Smoky Hill Third Transformer	
Project Description:	Install a 3rd 560 MVA 345/230 kV transformer at Smoky Hill Substation.
Project Location:	Arapahoe County
Anticipated ISD:	2029
Cost Estimate:	$29.2M

17. Leetsdale to Harrison 115 kV Circuit 9955 Uprate	
Project Description:	Rebuild 3.5 miles of 115 kV circuit 9955 from Leetsdale to Harrison to achieve a 756 MVA rating. Remove existing HPFF underground circuit and build a new XLPE circuit in a new concrete duct bank. Install 230 kV capable conductor for future voltage conversion. Uprate limiting elements at Leetsdale and Harrison Substations to achieve the required ratings.
Project Location:	Arapahoe County and City and County of Denver
Anticipated ISD:	2029
Cost Estimate:	$120.5M

18. Capitol Hill to Denver Terminal 115 kV Circuit 9007 Uprate	
Project Description:	Rebuild 2.5 miles of 115 kV circuit 9007 from Capitol Hill Substation to Denver Terminal Substation to achieve a 756 MVA rating. Remove existing HPFF underground circuit and build a new XLPE circuit in a new concrete duct bank. Install 230 kV capable conductor for future voltage conversion. Uprate limiting elements at Capitol Hill and Denver Terminal Substations to achieve the required ratings.
Project Location:	City and County of Denver
Anticipated ISD:	2029
Cost Estimate:	$94.2M

19. Midway Substation 230 kV Bus Uprate	
Project Description:	Replace limiting elements on the 230 kV bus tie at Midway substation to achieve a 2400-amp rating.
Project Location:	El Paso County
Anticipated ISD:	2026
Cost Estimate:	$4.1M

20. Midway Substation 230/115 kV Transformer Replacement	
Project Description:	Replace existing 230/115 kV transformer with a 280 MVA 230/115 kV transformer.
Project Location:	El Paso County
Anticipated ISD:	2027
Cost Estimate:	$6.9M

21. Cherokee to Broomfield 115 kV Circuits 9055/9558/9464 Uprate	
Project Description:	Rebuild 13 miles of double circuit 115 kV lines 9005/9558/9464 to achieve a 2000-amp rating. Consideration was given to reconductoring both circuits. The existing wood structures, previously modified from 1 to 2 circuits, are not able to support a large enough conductor to meet the required rating. Replace limiting elements at Cherokee, Semper, and Broomfield Substations to meet the 2000-amp requirement.
Project Location:	Adams and Jefferson Counties and City and County of Broomfield
Anticipated ISD:	2029
Cost Estimate:	$76.5M

22. Leetsdale to University 115 kV Circuit 9338 Uprate	
Project Description:	Reconductor one mile of 115 kV circuit 9338 to achieve a 1268-amp rating. Replace substation elements that do not meet the required rating. This project is expected to use an HTLS conductor.
Project Location:	City and County of Denver
Anticipated ISD:	2026
Cost Estimate:	$7.1M

23. San Luis Valley 115 kV Circuit 9431 Uprate	
Project Description:	Replace limiting elements at the San Luis Valley substation to achieve an 800-amp rating.
Project Location:	Alamosa County
Anticipated ISD:	2026
Cost Estimate:	$4.2M

24. Alamosa to Mosca to San Luis Valley 69 kV Circuits 6935/6936 Uprate	
Project Description:	Replace limiting elements at the San Luis Valley, Mosca, and Alamosa Plant substations to achieve an 800-amp rating. Rebuild 0.2 miles of line 6935. (The remaining 24 miles of circuit 6935 and 6936 have previously been rebuilt.)
Project Location:	Alamosa County
Anticipated ISD:	2028
Cost Estimate:	$15.2M

25. New 115 kV Line San Luis Valley to Alamosa Terminal	
Project Description:	Construct a new 115 kV circuit between the existing San Luis Valley and Alamosa Terminal Substations with a 1200-amp rating. The new line is assumed to be on a new 75’ wide easement, single pole steel construction, 477 kcmil ACSS “Hawk” conductor matching the rest of the 115 and 69 kV system in the SLV. Expand the Alamosa Terminal substation within the existing yard to accept the new 115 kV line. Build a new substation near the existing San Luis Valley Substation to accept the new 115 kV line. The existing 115 kV yard does not appear to be able to accept the new line. Coordination with Tri-State G&T will be required to determine the final viability of expansion vs new substation.
Project Location:	Alamosa County
Anticipated ISD:	2028
Cost Estimate:	$85.8M