RULE 3206 REPORT PROPOSED CONSTRUCTION OR EXTENSION OF TRANSMISSION FACILITIES

2022 THROUGH 2024

APRIL 30, 2021

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A. INTRODUCTION

In July of 2006, the Colorado Public Utilities Commission ("Commission" or "CPUC") adopted Rule 3206 as a part of 4 Code of Colorado Regulations ("CCR") 723-3, the Commission's rules regulating Electric Utilities. Rule 3206 sets forth requirements for construction and extension of transmission facilities, and Rule 3206(d) requires applicable utilities, including Public Service Company of Colorado ("Public Service" or the "Company"), to file annual reports on its planned transmission facilities. The purpose of the Rule 3206 report is to notify the Commission of pending or planned transmission system work and help the Commission determine if such projects (1) require a Certificate of Public Convenience and Necessity ("CPCN") under Rule 3102 and § 40-5-101, C.R.S., (2) do not require a CPCN, or (3) are in the ordinary course of business.

This report includes Public Service projects which are planned to be implemented within the next three years and conceptual projects that the Company is considering, but does not necessarily have planned in-service dates for at this time. "Planned Projects" are projects for which Public Service generally has a level of commitment such that proposed schedules for completion have been drafted, site control has been established, and/or the project has received budgetary approvals. These include projects that are necessary to meet reliability and load growth needs, planned interconnection of new generation, or to meet enacted public policy requirements, etc. "Conceptual Projects," on the other hand, may not have specific in-service dates identified, and their implementation likely depends on numerous factors, some of which include forecasted load growth and generation needs, economic considerations, public policy initiatives, and regional transmission development. The Company also includes alternatives considered for each project, including consideration of energy storage systems, consistent with Rule 3206(d)(I)(D).

This report is divided into several sections. The first section is this introduction to provide some background and a brief explanation of what is included with this filing.

Section B includes new projects that may require a CPCN under Commission rules and for which the Company plans to pursue a CPCN absent a Commission ruling otherwise. Generally, these are projects that include:

1. Facilities the Company believes are outside the ordinary course of business;
2. A new 230 kV or 345 kV transmission facility that is <u>not</u> a radial transmission line servicing a single retail customer; or
3. Transmission facilities between 115 kV and 138 kV that do not meet the appropriate noise and magnetic field thresholds established by Commission Rules and/or are not in the ordinary course of business.

The Company is not presenting any projects in this section; however, see the related Section G below.

Section C includes projects that may require a CPCN under Commission rules, but for which the Company is requesting a Commission determination that a CPCN is not required. The Company is presenting one project in this category.

Section D of this filing includes projects for which a CPCN is likely not required under Commission rules. For all projects in this section, the Company is requesting affirmative rulings that the projects are in the normal course of business. The Company is presenting one project in this category.

Section E of this filing provides an update of projects that have been listed in past Rule 3206 filings, or for which the Company has initiated the CPCN process since its last Rule 3206 filing.

Section F of this filing includes projects generally considered conceptual at the time of filing and which are being provided for informational purposes only. This 2021 filing includes "Long Range Distribution Planning Substation Projects."

Section G of this filing includes projects associated with the Colorado Energy Plan Portfolio ("CEPP") for which Public Service will file additional CPCN(s) pursuant to Commission Decision No. C18-0761 issued in Phase II of the Company's most recent Electric Resource Plan ("ERP"), Proceeding No. 16A-0396E.

Transmission Costs

Unless otherwise stated, all costs and budgets in this filing are "Transmission Costs," which Public Service considers to be the procured costs of each project's physical Transmission Facilities as defined by Rule 3001(kk) plus the associated subsidiary costs necessary to design, install, and operate those facilities. In keeping with Rule 3001(kk), "Transmission Facilities" are "those lines and related substations designed and operating at voltage levels above the utility's voltages for distribution facilities, including but not limited to related substation facilities such as transformers, capacitor banks, or breakers that are integral to the circuitry of the utility's transmission system." More specifically, for purposes of this Report, Transmission Costs include cost estimates associated with high voltage transmission devices and machines, labor and contractor rates, materials, overhead, contingency reserves, transmission land acquisition, transmission right-of-ways, and engineering.

Public Service does not include distribution-level voltage facilities (such as dedicated substations and feeders), generation facilities, which may (or may not) include bulk energy storage as part of their injection capabilities/technology, or distribution siting and land rights activities in Transmission Costs. The Company provides relevant distribution and distribution land costs in applicable CPCN applications. Unless otherwise noted, all costs listed in this filing are Transmission Costs as defined above.

Due to the fact that Transmission Cost estimates are refined during a project's lifecycle, the Transmission Cost estimates presented in this report are subject to change between the time the Company files its Rule 3206 Report and the time it files, or presents, other documents related to a project, such as a CPCN application or presentations at stakeholder outreach meetings.

B. NEW PROJECTS THAT MAY REQUIRE A CPCN

1. None

C. NEW PROJECTS FOR WHICH PUBLIC SERVICE REQUESTS THE COMMISSION DETERMINE A CPCN IS NOT REQUIRED

1. Colorado Springs Utilities Unintended Flow Mitigation Project

Public Service Company of Colorado Partnership Project - Colorado Springs Utilities Unintended Flow Mitigation Project

Name of the project:

Colorado Springs Utilities Unintended Flow Mitigation Project

Project background:

Public Service's Front Range system consists of 345 kV and 230 kV lines that run from the Comanche Station in Pueblo, to the Daniels Park and Waterton substations on the south side of the Denver-metro area. That transmission system is owned and operated by Public Service and is used to deliver generation from resources in southern Colorado, to the Denver-metro customer load center. The Colorado Springs Utilities ("Springs Utilities") transmission system is electrically in parallel to the Public Service high voltage transmission system and consists primarily of 115 kV and 230 kV transmission lines. Since the Springs Utilities' transmission system is electrically in parallel to the Public Service transmission path to Denver, some of the power serving Public Service's system inadvertently flows through the Springs Utilities' transmission system and has the potential to create an unacceptable loading situation on certain lines in the Springs Utilities' transmission system.

Inadvertent flow is best described as the unintended flow away from the main path of power flow due to the interconnected nature of the Transmission System.

The Colorado Springs Utility Unintended Flow Mitigation Project was first identified in the Company's 2018 Rule 3206 Report (**Proceeding No. 18M-0005E**), where it was titled as the "Monument – Flying Horse 115 kV Phase Shifting Transformer" project. There, the Company identified the project as, "… adding a phase shifting transformer ("PST") at the Monument Substation, on the Monument-Flying Horse 115 kV transmission line to control overloads due to inadvertent power flows through the Colorado Springs Utilities … transmission system." As stated in the 2018 Report, the Company identified this proposed PST solution through a preliminary analysis and indicated there were ongoing studies to remedy power flow overloads occurring on Springs Utilities' transmission system due to the inadvertent flows.

In the Company's 2019 Rule 3206 Report (**Proceeding No. 19M-0005E**), under "Projects for Commission Information-Other Projects-Colorado Springs Loading Mitigation," Public Service reported that on-going studies indicated a series reactor would mitigate the potential unintended flows on the Springs Utilities' transmission system as an alternative to the PST; however, analysis and studies were still on-going.

For more than three years, the Colorado Springs Utilities Unintended Flow Mitigation Project has been studied through the Douglas, Elbert, El Paso, Pueblo (“DEEP”) Subcommittee of the sub regional Colorado Coordinated Planning Group (“CCPG”). Participation in the DEEP subcommittee included Public Service, Springs Utilities, Tri-State Generation and Transmission (“TSGT”), Black Hills Energy (“BHE”) and Western Area Power Administration (“WAPA”). The objective of the subcommittee was to identify an effective, long-term, transmission solution to prevent the overloads caused by the unintended power flows observed on the Springs Utilities’ transmission system.

Over this time, Public Service has also been involved in direct and ongoing dialogue with Springs Utilities about how to jointly address these issues and the construction difficulties with locating an appropriate site(s) for the project(s).

Project description:

Public Service and Springs Utilities have reached mutual agreement on a joint project between the two utilities to resolve the inadvertent power flow issue on the Springs Utilities’ transmission system; consistent with the joint project identified in the DEEP study as the recommended long-term solution.[1] Under this agreement, Springs Utilities will take on all engineering and construction responsibility associated with the project, and Public Service will contribute funding for the project. Public Service will have an ownership share in the new facilities commensurate with its portion of the capital costs associated with construction. More specifically, Springs Utilities will (1) install a series reactor at its Flying Horse 115 kV substation, and (2) tap Springs Utilities’ Fuller – Cottonwood 230 kV line via the Springs Utilities’ Briargate Substation and add a 230/115 kV transformer. Public Service will have partial funding responsibility (an up-front capital contribution up to $12 million and ongoing O&M[2] responsibility commensurate with its ownership share), while Springs Utilities will engineer, construct, operate, and maintain the facilities. The series reactor changes the impedance of the line and reroutes power from congested facilities and may be considered an application of Advanced Transmission (“ATT”).

The funding responsibility is based on the estimated $12 million cost for a medium-term, sub-optimal, alternative solution wherein Public Service would tap the Springs Utilities-owned portion of the Flying Horse – Monument 115kV line and build a new, greenfield site for the series reactor. This joint project also provides Public Service the possibility in the future to sell its share of the assets back to

[1] The DEEP study report has not been finalized yet as it is still pending review and approval from other subcommittee members.
[2] O&M costs are not included in the 3206 Report.

Springs Utilities once the assets reach half of their book lives (approximately 29 years).

This recommended alternative will provide the following benefits to Public Service and Springs Utilities:

- Mitigate the overloads in the Springs Utilities' system due to unintended flows from Public Service's system; and,
- Provide redundancy in case of failure of the series reactor.

Public Service believes this project does not require a CPCN for the following reasons:

- The project will be designed, engineered, constructed, and operated by Springs Utilities.
- The series reactor will be located within the existing Springs Utilities-owned Flying Horse substation located in the City of Colorado Springs and designed and operated at 115kV. No expansion of the substation will be required.
- The Briargate 230/115kV transformer will be installed within the existing Springs Utilities-owned Briargate substation located in the City of Colorado Springs. Springs Utilities may need to expand its substation to accommodate the new transformer, and associated bus and termination equipment to accommodate the termination of the Fuller – Cottonwood 230kV transmission line.
- Projected Transmission Cost of the project assumed by Public Service will be capped at $12 million (of the total projected Transmission Cost of $20.6 million). Springs Utilities will be responsible for project costs in excess of $12 million.

Project alternatives considered:
The DEEP subcommittee studied several alternatives for this project, which are noted below (1 through 12), along with a brief explanation of why the alternative was not selected:

1. Reconductor the Springs Utilities' Cottonwood – Briargate and Cottonwood – Kettle Creek 115 kV lines to 280 MVA. This alternative resolved the overloads on the two 115 kV lines but shifted the inadvertent flow issue to other parts of the Springs Utilities' system, so it was determined not to be an effective solution.
2. Operating Guides to open the Palmer Lake – Monument 115 kV line. This is an existing Operating Guides but becomes ineffective at limiting inadvertent power flows as injection levels increase on Public Service's system. It was therefore determined not to be an effective or preferred solution.
3. Permanently open the Monument – Flying Horse 115 kV line and build a second 115 kV line from Springs Utilities' Flying Horse Substation to the Kettle Creek Substation. This alternative would not completely mitigate the inadvertent flow issue and would instead shift the inadvertent flow issue from

the Springs Utilities' system to TSGT's parallel 115 kV network between Midway and Fuller. It was therefore determined not to be an effective solution.

4. Limit the flow through Springs Utilities' system using a flow-limiting device. The two options evaluated were:

- 4(a) – Install a phase shifting transformer to regulate the flow on Monument – Flying Horse 115 kV to 35 MW. The extra phase angle difference injected at the Monument Substation due to the phase shifting transformer causes an angle differential compared to the other end of the Mountain View Electric Association ("MVEA") distribution system connected to Fuller. This would present operational concerns as it would require radial operation of MVEA's system. It was therefore determined not to be a preferred solution.
- 4(b) – Install a series reactor (Z= 0.2p.u.) to regulate power flow at 35 MW instead of a phase shifter. This alternative was determined not to be a long-term solution since a failure of the series reactor would require long lead times for equipment replacement and the associated outage period would be lengthy. The lengthy outage period would re-introduce the inadvertent power flows and present reliability concerns in the event the Springs Utilities' lines were overloaded. It was therefore determined not to be an effective or preferred solution. This is the alternative from which the $12 million greenfield site cost estimate was developed.

5. Split the Fuller 230 kV station configuration to separate Public Service assets from Springs Utilities and TSGT. This alternative is not effective in alleviating the overloads caused by the inadvertent flow, and it was therefore determined not to be an effective solution.

6. Split the Monument Substation to separate Public Service and TGST's assets from Springs Utilities using a phase shifting transformer. This alternative would be effective in mitigating overloads on the Springs Utilities' system. However, as stated in Alternative 4(a), due to the operation constraints associated with the phase shifting angle difference caused by the phase shifting transformer, this alternative was determined not to be a preferred solution.

7. Series Compensation. The two options evaluated were:

- 7(a) Series compensate the Comanche – Daniels Park double circuit 345 kV lines using cap banks to increase flow on these lines.
- 7(b) Series compensate the Comanche – Daniels Park double circuit 345 kV lines, and the Daniels Park – Fuller 230 kV line using cap banks

Neither of these alternatives were determined to be effective in mitigating the CSU system overloads, and were therefore determined not to be effective solutions.

8. Build a new 115 kV line from Fuller Substation to Flying Horse Substation. This alternative was determined to not be effective in mitigating the inadvertent flow issue. Also, engineering experience indicated this alternative would not be a least cost alternative. It was therefore determined not to be an effective or preferred solution.

9. Build a new 115 kV line from Fuller Substation to Monument Substation. This alternative is not effective in mitigating the inadvertent flow issue. Also, engineering judgement indicates this alternative would not be a least cost alternative. It was therefore determined not to be an effective or preferred solution.
10. Reroute the existing Fuller – Cottonwood 230 kV line to terminate at Kettle Creek 230 kV instead of Cottonwood and add a new 230/115 kV transformer at Kettle Creek. This alternative would mitigate the inadvertent flow issue for the existing generation but would not perform well at higher injection levels. Engineering judgement also indicates this alternative would not be a least cost alternative. It was therefore determined not to be an effective or preferred solution.
11. Build a new 230 kV line from Fuller to Kettle Creek instead of re-routing the existing line. Also add a new 230/115 kV bank at Kettle Creek. This alternative would mitigate the inadvertent power flow issue for the existing generation, but would not perform well at higher injection levels. Engineering judgement also indicates this alternative would not be a least cost alternative. It was therefore determined not to be an effective or preferred solution.
12. Reroute the existing Fuller – Cottonwood 230kV line to Briargate and add a new 230/115 kV, 150 MVA transformer at CSU's Briargate Substation. This alternative becomes ineffective at limiting the inadvertent power flows as injection levels increase on Public Service's system. It was therefore determined not to be an effective or preferred solution.
13. Energy Storage: Energy storage would be an ineffective alternative to resolve the overload issue because the mitigation requires limiting the inadvertent flow. However, when the energy storage resource discharges, its output flow on the system would worsen the overload. It was therefore determined not to be an effective or preferred solution.

Estimated Transmission Cost of the project:

$12 million (Public Service's agreed-to capital contribution)
$ 20.6 million (total project Transmission Cost)

Projected date for the start of construction of the project:

2021

Estimated date of completion of the project:

Briargate Tap - December 2023
Flying Horse Series Reactor - 2024

Estimated in-service date of the project:

Briargate Tap - December 2023
Flying Horse Series Reactor – 2024

Proposed general location:

City of Colorado Springs

Prudent avoidance measures being evaluated for transmission facilities:

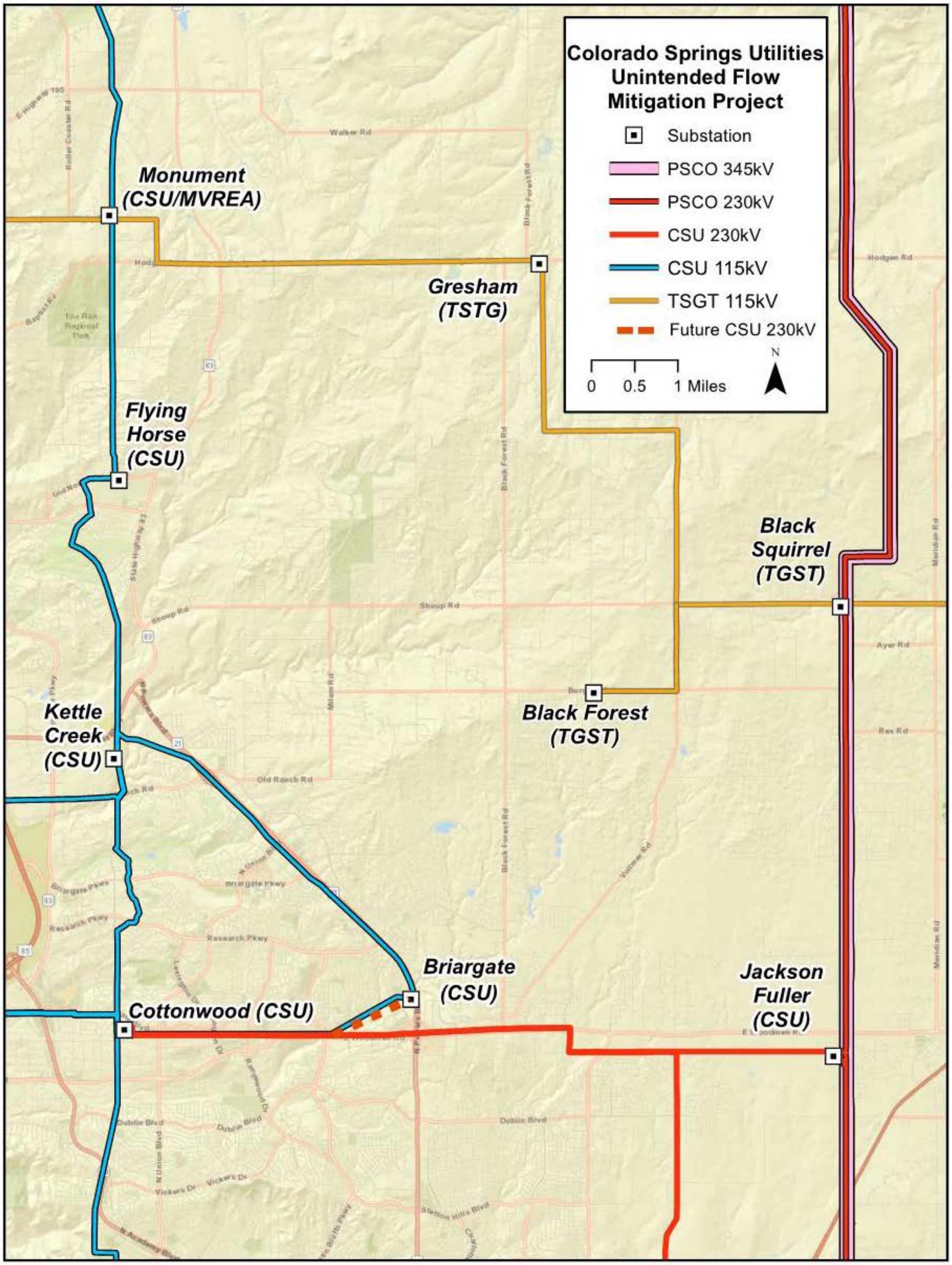
NA. Project will be engineered, constructed, operated, and maintained by Colorado Springs Utilities.

Requested Commission Findings

Springs Utilities is not a Commission-jurisdictional entity and will be the entity undertaking the engineering, construction, operations, and maintenance activities described above. Rule 3206(a) provides, in pertinent part, that "No utility and no cooperative electric association which has voted to exempt itself pursuant to § 40-9.5-103, C.R.S., may commence new construction, or extension of transmission facilities or projects until either the Commission notifies the utility that such facilities or projects do not require a certificate of public convenience and necessity or the Commission issues a certificate of public convenience and necessity."[3] Here, Public Service, while it is subject to the Commission's ratemaking jurisdiction, is not the party engaged in constructing or extending the transmission facilities. The project involves construction that will be completed by Springs Utilities and interconnect with existing facilities that are owned by Springs Utilities, a non-Commission-jurisdictional municipal utility. Further, the project's location is entirely within both Springs Utilities' service territory and the municipal boundaries of the City of Colorado Springs. While Public Service does not believe that this project falls within the scope of Rule 3206's CPCN requirements, it notes that Public Service will have an ownership interest in some of the new transmission facilities, and that it plans to seek cost recovery for costs associated with this project in the future.

Accordingly, Public Service requests that the Commission determine that no CPCN is needed for the Company's ownership share of the costs of the Colorado Springs Utilities Unintended Flow Mitigation Project as the project does not fall within the purview of Rule 3206.

[3] Rule 3206(a) is based in part on § 40-5-101, C.R.S., which provides that "a public utility shall not begin the construction of a new facility, plant, or system or the extension of its facility, plant, or system without first obtaining from the commission a certificate that the present or future public convenience and necessity require, or will require, the construction or extension."


Colorado Springs Utilities
Unintended Flow
Mitigation Project
Substation
PSCO 345kV
PSCO 230kV
CSU 230kV
CSU 115kV
TSGT 115kV
Future CSU 230kV
0 0.5 1 Miles
N
Monument
(CSU/MVREA)
Gresham
(TSTG)
Flying
Horse
(CSU)
Black
Squirrel
(TGST)
Kettle
Creek
(CSU)
Black Forest
(TGST)
Briargate
(CSU)
Jackson
Fuller
(CSU)
Cottonwood (CSU)
Walker Rd
Shoup Rd
Old Ranch Rd
Research Pkwy
Dublin Blvd
Black Forest Rd
Vollmer Rd
Hodgen Rd
Ayer Rd
Rex Rd
Meridian Rd

D. PROJECTS PUBLIC SERVICE CONSIDERS TO BE IN THE ORDINARY COURSE OF BUSINESS PURSUANT TO RULE 3206(B)(I) OR (II) AND WHICH THE COMPANY REQUESTS THE COMMISSION FIND TO BE IN THE ORDINARY COURSE OF BUSINESS

1. Barker Substation (Distribution 230/13.8 kV, 50MVA), Re-Affirmation

Public Service Company of Colorado Transmission Construction Project

Name of the Project:

Barker Substation (Distribution 230/13.8 kV, 50MVA)

Background and Procedural History:

The Barker Substation (Distribution 230/13.8 kV, 50MVA) project was initially submitted in the Company's Rule 3206 Report filing in April of 2010 (**Proceeding No. 10M-206E**). The project description in the 2010 filing described the project as follows:

> This project proposes to construct a distribution substation called Barker Substation at the existing substation site near 20th Avenue & Blake Street, across from Coors Field in Denver, Colorado. For the transmission portion of the project, Public Service Company of Colorado ("Public Service") proposes to install approximately 2000 feet of double-circuit (in-and-out) 230kV underground transmission between Lacombe and Barker Substations. Public Service will install two new 230/13.8kV, 50MVA transformers and associated equipment at the Barker Substation. The second transformer is required to provide backup if the first transformer fails. This project is needed to supply the continuing load growth in the Lower Downtown area and to eliminate system intact overloads that will exist on the ninth network in Denver. The new underground cables will utilize 1000 feet of two existing steel parallel pipes. Please refer to Attachment E for the orientation map of the project.

The Company's 2010 3206 Report filing reported a projected Transmission Cost of $16.4 million and in-service date of May 2015. The Company explained in the filing that this project was a distribution project occurring in the ordinary course of business; therefore, no CPCN is required. The Commission agreed and ruled that the project did not require a CPCN (**Decision No. C10-0644, Ordering ¶ 2**).

In Public Service's 2012 Rule 3206 Report (**Proceeding No. 12M-165E**), the Company adjusted the in-service date to 2020 due to slower than forecasted distribution load growth in the area.

The following year, in 2013, the Company indicated in its Rule 3206 Report (**Proceeding No. 13M-0019E**) that the project's in-service date had moved to June of 2021 "after reassessing the project's need" based around changing/delayed forecasted load growth.

In the Company's 2015 Rule 3206 Report (**Proceeding No. 15M-0043E**) Public Service noted the projected Transmission Cost had increased to $18 million. In the Company's 2016 3206 Report (**Proceeding No. 16M-0009E**), the project's in-service date shifted to December of 2021, with a Transmission Cost of $18.1 million. These increases in Transmission Costs reflected updated material, labor, and construction estimates.

In the Company's 2018 Rule 3206 Report (**Proceeding No. 18M-0005E**), the Company reported a projected in-service date of May 2022 due to staging the construction installations of the two transformers, one in December of 2021 and the other in May 2022, and projected Transmission Costs of $20.5 million. The cost increase was due to updated labor, construction, contingency, and escalation costs.

In the Company's 2019 Rule 3206 Report (**Proceeding No. 19M-0005E**), the underground transmission design requirements for the project were updated to reflect current standards to use solid dielectric Cross-Linked Polyethylene ("XLPE") underground conductor. As explained below, these updates resulted in an increase of the Transmission Costs to $32.5 million.

Last year, Public Service's Rule 3206 Report (**Proceeding No. 20M-0005E**) listed the in-service date as June 2023 due to delayed load growth, and a Transmission Cost of $30.5 million. This cost projection reflected refined Transmission Cost estimates and the design updates indicated in the Company's 2019 Rule 3206 filing.

2021 Project Description

The Barker Substation Project is needed to serve growing demand on the transmission network servicing Downtown Denver and the non-network load in the surrounding service territory (a map is provided at the end of this section showing where the project is located). Presently, Public Service has five substations (California, Lacombe, Elati, Capitol Hill, Denver Terminal) that provide electric service in and around the downtown area and another two substations (North and Argo) that serve areas just to the north of the downtown area. The existing substations, and existing downtown area 115 kV network, have been expanded and do not have enough transmission capacity at 115 kV or the physical space within the substations to serve the anticipated future demand in Downtown Denver.

This project is needed to serve increasing distribution load and address reliability concerns. The project scope includes installing one 50 MVA 230/13.8kV distribution transformer including switchgear and feeders in 2025; and a second 50 MVA 230/13.8kV distribution transformer, switchgear and feeders in 2026. The Substation will be designed and constructed as a Gas Insulated Substation ("GIS") due to a limited substation area, which is located in Downtown Denver adjacent to Coors Field. Scope also includes the build-out of transmission substation and 2700 feet of 230kV, underground transmission line facilities (to the 230 kV Lacombe Substation).

The main difference of the planned project from the initial 2010 Report filing is the type of conductor employed in the 230 kV underground transmission line. The current standard is to use a solid dielectric Cross-Linked Polyethylene ("XLPE") underground conductor as opposed to a High-Pressure Fluid Filled ("HPFF") underground conductor system to transmit the required energy.

In addition to being compromised during RTD's light rail line construction, the 1000 feet of existing steel parallel pipes (mentioned in the 2010 Report) were constructed to support the HPFF cable system. HPFF technology has become obsolete and is currently supported by a single cable manufacture. Integrity of these conduits withstanding, the existing steel parallel pipes cannot accommodate current Xcel Energy standards. Due to the lack of vendors available to supply competitive operational and maintenance support, the integrity and size of the previously installed conduit, a solid dielectric XLPE conductor has been chosen.

As mentioned, the XLPE cables will need new underground conduit and duct banks between the Lacombe and Barker Substations. Two cables will be installed for each phase of the double circuit. Portions of this underground cabling system will utilize horizontal directional drilling ("HDD") methods to minimize impacts on the surrounding downtown area. Among other things, a 1950' trenchless installation will be necessary to get through an underpass, where there are several levels of vehicular traffic and the RTD rail line, requiring significant coordination of construction and multiple mobilizations and demobilizations.

<u>2021 Transmission Cost Estimate and In-Service Date</u>

In order to maintain reliability, the project will be in-serviced in two stages, first addressing the cable servicing critical downtown network load, followed by work on the cable serving non-network load second.

1) First transformer in-service by October 31, 2025.
2) Second transformer in-service by June 15, 2026.

The original Transmission Cost reported in the 2010 filing was $16.4 million. This cost assumed that Public Service's existing infrastructure supporting underground transmission conductors would be sufficient for the project's engineering parameters. The 2020 Rule 3206 Report listed the Transmission Costs at $30.5 million (decreased from the 2019 filing with Transmission Costs of $32.5 million), reflecting the updated XLPE conductor and associated underground work. The current estimate for the Transmission Costs are $36.8 million. This cost reflects more refined cost estimates for materials and labor since the Company's 2019 and 2020 Rule 3206 filings.

<u>2021 Project Alternatives Considered</u>

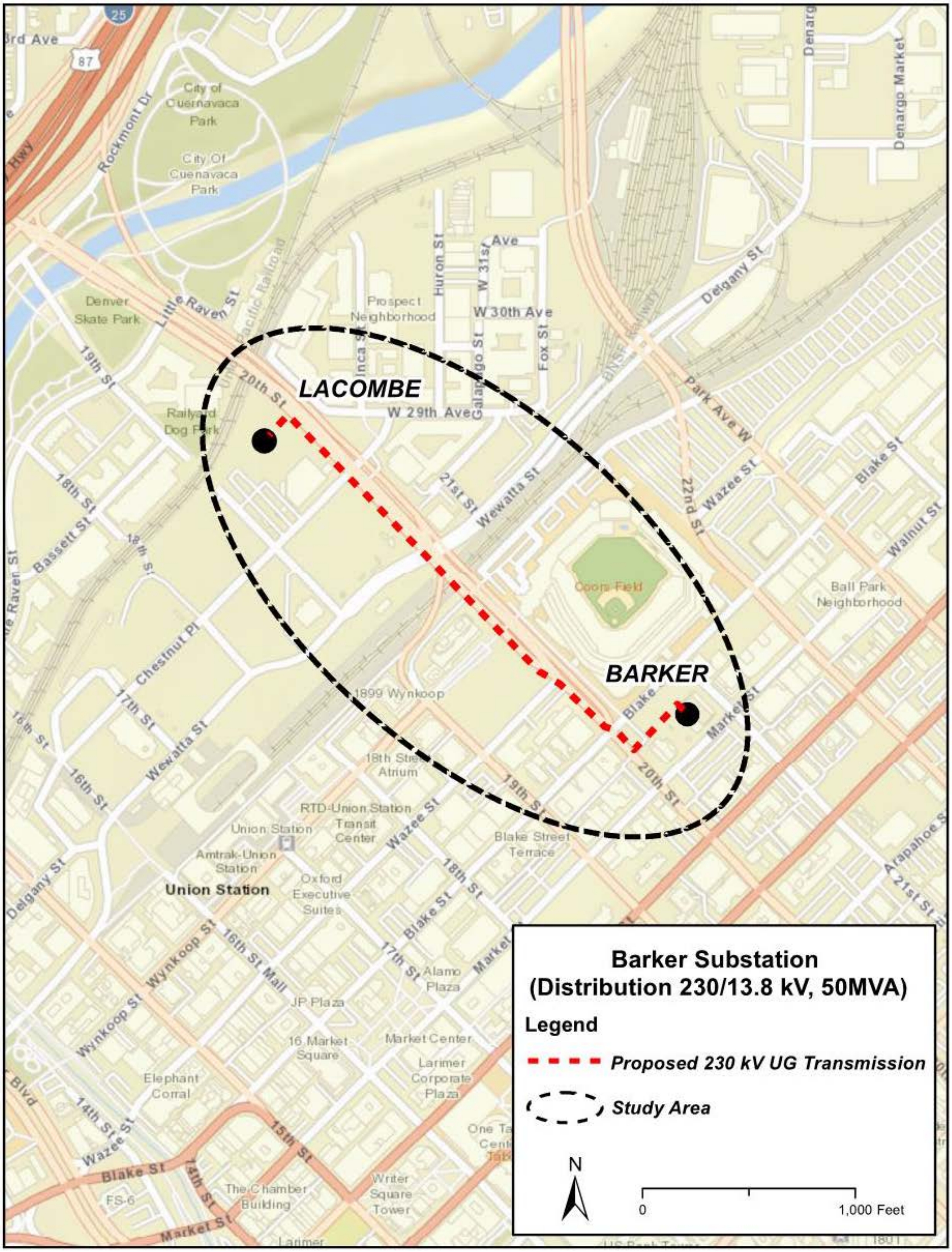
1. The Company explored servicing load from a different location(s), at both 230 kV and 115 kV transmission service, within the downtown area. Public Service determined these alternatives are insufficient (or unreasonable) given the lack of available capacity in the surrounding 115 kV (Downtown Denver Area) network,

coupled with the high costs of land acquisition in the downtown area, scarcity of suitable sites, routing of transmission lines to service a potential site, and permitting costs.

2. The Company considered how an Energy Storage System(s) ("ESS") could be used as a transmission alternative but determined that ESS is not a viable option for this load-serving project. This project proposes a greenfield substation, which is absent of the needed infrastructure to support charging of an ESS solution.
3. A non-wire alternative ("NWA") study was performed from a distribution perspective, which evaluated the need for the Barker Substation. Options included distributed energy resources, both with and without battery storage; batteries on their own; geo-targeted demand-side management; and combinations of technologies that could potentially eliminate the need for a traditional wire/infrastructure solution or could defer the need so that the in-service date could be shifted into future years. However, it was determined that an NWA would be economically and physically impractical given the siting requirements of such solution(s) and the developing load growth to be served by this project.

Requested Commission Findings

The transmission connection to the Barker Substation consists of the same 230 kV underground transmission and transformer requirements originally included in the Company's 2010 Rule 3206 Report, where the Commission determined was in the ordinary course of business. Although the engineering design of the facility's connection has been updated to reflect current equipment and standards, the project's overall scope, purpose, and need have not changed in any substantive manner. The Company therefore requests that the Commission re-affirm the project is in the ordinary course of business and no CPCN is needed for the project.


LACOMBE
BARKER
Barker Substation
(Distribution 230/13.8 kV, 50MVA)
Legend
Proposed 230 kV UG Transmission
Study Area
N
0
1,000 Feet

E. STATUS OF PROJECTS LISTED IN PRIOR REPORTS

The Transmission Costs reported in the following table are for Transmission facilities only and reported in millions of dollars.

TBD = To Be Determined
ISD = In-Service Date
Report = Rule 3206 Filing

Table 1 below contains a list of projects that have been identified in past Rule 3206 Reports that have been completed/in-serviced or canceled since the Company filed its last Rule 3206 Report. No replacement projects have been identified over the past year.

TABLE 1

Projects In-Service, Canceled, or Replaced Since 2020			
Item #	**Project Name**	**Change in Status/Cost**	**Reason for Change**
1	NREL 115 kV Substation	Yes	In Service/Completed
2	Interconnection at the Existing 230 kV Keenesburg Substation (Bid ID 090)	Yes	In Service/Completed
3	Interconnection at the Existing Boone 230 kV Substation (Bid ID 035)	Yes	Project Replaced with Bid 077
4	Weld County Load Serving Request	Yes	Project Canceled
5	Monument – Flying Horse Phase Shifting Transformer / Colorado Springs Load Mitigation	Yes	Project replaced with Colorado Springs Utilities Unintended Flow Mitigation Project

Table 2 below contains a comprehensive list of planned Transmission projects over the next three years, along with relevant information on each project, including the name, any change in status/cost from the 2020 Rule 3206 Report, project status, and the projected Transmission Costs. The Transmission Costs reported in the following table are for Transmission facilities only and reported in millions of dollars.

TABLE 2

Projects by In-Service Date (ISD)				
2021 ISD Projects				
Item #	**Project Name**	**Change in Status / Cost**	**Project Status**	**Transmission Cost ($ million)**
6	NONE			
2022 ISD Projects				
Item #	**Project Name**	**Change in Status / Cost**	**Project Status**	**Transmission Cost ($ million)**
7	Avery 230/13.8 kV, 28 MVA Distribution Substation	Yes	ISD is 05/2022. A CPCN was granted for this project. (**Proceeding No. 15A-0159E, Decision No. C15-0461)**	Transmission Cost increased from $10.3 to $10.8 due to updated forecasts reflecting updated material, labor, and price estimates.
8	High Point Distribution Substation 230-13.8 kV	Yes	ISD is 10/2022. CPCN for associated Transmission and Distribution facilities filed. (**Proceeding No. 20A-0082E**. **Decision No. R20-0725, exceptions denied by Decision No. C20-0886**)	Confidential as land acquisition negotiations are ongoing, please see Proceeding No. 20A-0082E and Decision No. R20-0725 for additional detail.
9	Mirasol 230 kV Switching Station	Yes	ISD is 06/2022, Public Service anticipates filing a CPCN in Q2 of 2021.	Transmission Cost estimate is $24, cost increase from initial estimate of $12 due to better definition of project scope.
10	Tundra 345 kV Switching Station	Yes	ISD is 06/2022, Public Service anticipates filing a CPCN in Q2 of 2021.	Transmission Cost estimate is $21.4, cost increase from initial estimate of $12 due to better definition of project scope.

11	Midway Solar Interconnection	Yes	ISD is 05/2022, Public Service anticipates filing a CPCN in Q2 of 2021.	Transmission Costs were $0.6 and are now $2 due to better definition of project scope.
12	CEPP: Greenwood – Denver Terminal 230 kV Transmission	Yes	ISD is 12/2022. A CPCN was granted on September 10, 2020. (**Proceeding No. 20A-0063E, Decision No. C20-0648)**	Transmission Costs increased from $50.1 to $61 reflecting updated material, labor, and price estimates.
2023 ISD Projects				
Item #	**Project Name**	**Change in Status / Cost**	**Project Status**	**Transmission Cost ($ million)**
13	Ault – Cloverly 230/115 kV Transmission	Yes	ISD changed from 12/2022 to 12/2023 due to permitting delays. A CPCN was granted. **(Proceeding No. 17A-0146E, Decision No. R18-0135)**	Transmission Cost increase from $66.7 to $76 due to forecasts reflecting updated material, labor, and price estimates.
14	Titan Distribution Substation 230/13.8 kV Project (also referred to as Waterton Expansion TR4)	Yes	ISD is 5/2023. A CPCN was granted. (**Proceeding No. 18A-0199E, Decision No. C18-0427**)	$13 (no Transmission Cost change, project name expanded)
15	Bluestone Valley Substation Phase 2	Yes	ISD is 2023. A CPCN is not required. (**Proceeding No. 09M-392E, Decision No. C09-0681**) The Company has filed an Amended 2009 Rule 3206 Report requesting the Commission reaffirm its finding no CPCN is necessary. (**Proceeding No. 09M-392E**)	$14.1
16	Dove Valley Distribution Substation 115/13.8 kV	No	ISD is 12/2023. Project determined to be "in the ordinary course of business." (**Proceeding No. 18M-0005E, Decision No. C18-0843**)	TBD. The project is under review and the Company will update the Commission as appropriate in the future.

17	Climax-Robinson Rack-Gilman 115 kV Transmission	Yes	ISD changed from 2022 to 2023 due to permitting delays. This project is in the ordinary course of business. (**Proceeding No. 19M-0005E, Decision No. C19-0638**)	$15
18	CEPP: Voltage Control	Yes	ISD is 12/2023. A CPCN on September 10, 2020. (**Proceeding No. 19A-0728E, Decision No. C20-0648**)	Transmission Cost updated from $93.6 to $95.3 due to updated material, labor, and price estimates. (Reflects CEPP: Voltage Control group total.)
2024 ISD Projects				
Item #	**Project Name**	**Change in Status / Cost**	**Project Status**	**Transmission Cost ($ million)**
19	Colorado Springs Utilities Unintended Flow Mitigation Project; (Replaces Monument – Flying Horse Phase Shifting Transformer / Colorado Springs Load Mitigation)	Yes	ISD is 2024. Project currently before the Commission in this filing. See Section C above for more information. (**Proceeding No. 21M-0005E**)	$12.2[4]
20	Gilman – Avon 115 kV Line and 45 MVAR Capacitor Bank at Vail Substation	Yes	ISD change from 12/2022 to 12/2024 to coordinate timing with Holy Cross Electric. This project is in the ordinary course of business and a CPCN is not required. (**Proceeding No. 15M-0043E, Decision No. C15-0590**)	$11.4
2025 ISD Projects				

[4] The $0.2M is reflective of administrative overhead Public Service will incur associated with the project.

Item #	Project Name	Change in Status/Cost	Project Status	Transmission Cost ($ million)
21	May Valley-Longhorn Extension (part of Colorado Power Pathway)	No	ISD is 12/2025, if approved by the Commission. Supplemental filing (**Proceeding No. 20M-0005E**), CPCN pending before the Commission. (**Proceeding No. 21A-0096E**)	$250
2026 ISD Projects				
Item #	**Project Name**	**Change in Status / Cost**	**Project Status**	**Transmission Cost ($ million)**
22	Barker Substation (Distribution, 230/13.8 kV, 50 MVA)	Yes	ISD for Bank #1 changed from 10/2022 to 10/2025. ISD for Bank #2 changed from 6/2023 to 06/2026. Changes are due to delayed load growth. Previously, no CPCN is required. (**Proceeding No. 10M-206E, Decision No. C10-0644**) Through the instant proceeding, Public Service requests reaffirmation of the decision.	Transmission Cost increase from $30.5 to $36.8 due to refined cost estimates based upon the new ISD.
23	Stock Show Distribution Substation 115/13.8kV	No	ISD is 2026. Project determined to be "in the ordinary course of business." (**Proceeding No. 18M-0005E, Decision No. C18-0843**)	TBD
24	Weld – Ennis 230/115 kV Transmission Project	Yes	ISD was 2025 is now 2026 due to ongoing system studies. May require a CPCN. (**Proceeding No. 20M-005E, Decision No. C20-0477**)	$98

2027 ISD Projects				
25	Colorado's Power Pathway 345 kV Transmission Project	No	ISD for project is 12/2027, with segment ISD's as: Segment 2 & 3 in 2025 Segment 1 in 2026 Segment 4 & 5 in 2027. Supplemental filing (**Proceeding No. 20M-0005E**) CPCN pending before the Commission. (**Proceeding No. 21A-0096E**)	$1,700 (all segments)
ISD To Be Determined				
Item #	**Project Name**	**Change in Status/Cost**	**Project Status**	**Transmission Cost ($ million)**
26	Glenwood Springs – Rifle 69/115 kV Conversion	No	ISD is TBD due to delayed load growth.	TBD
27	Hartsel – Tarryall 230 kV Switching Station	Yes	ISD is TBD, a CPCN will be filed in the future.	Transmission Costs were $12 and are now currently under determination as scope is refined. Also, see Section G.
28	Monfort 15 MVAR, 44 kV Capacitor Banks	No	ISD is set to TBD based on local load growth. No CPCN is required. (**Proceeding No. 13M-0019E, Decision No. C13-0879**)	$1.3
29	New Castle 115/69-24.9 kV Substation (Distribution, 16 MVA)	No	ISD is TBD based on local load growth. Project assumes Glenwood – Rifle project (26) occurs. No CPCN is required. (**Case No. 6396, Decision No. C08-0676**)	$1.4
30	Parachute – Cameo 230 kV Transmission Line	No	ISD is TBD based on local load growth. A CPCN is required for this project. (**Proceeding No. 10M-206E, Decision No. C10-0644**)	$48.1

31	Rifle (Ute) – Story Gulch 230 kV Transmission Line Project	No	ISD is TBD based on local load growth. A CPCN is required for this project. (**Proceeding No. 10M-206E, Decision No. C10-0644**)	$24
32	Vasquez 115/13.8 kV, 28 MVA # 2 Transformer	No	ISD is TBD due to load growth. This project is in the ordinary course of business and a CPCN is not required. (**Proceeding No. 15M-0043E, Decision No. C15-0590**)	$0.3
33	Wheeler – Wolf Ranch 230 kV Transmission Project	No	ISD is TBD based on local load growth. No CPCN is required. (**Proceeding No. 14M-0061E, Decision No. C14-0732**)	$17
34	Wilson # 1 Sub (Distribution, 115/13.8 kV, 14 MVA)	No	ISD is TBD based on local load growth. No CPCN is required. (**Proceeding No. 10M-206E, Decision No. C10-0644**)	$3.5

F. PROJECTS FOR COMMISSION INFORMATIONAL PURPOSES

These conceptual projects are not currently planned, but could become planned projects prior to the Company making its next Rule 3206 filing.

1. Long Range Distribution Planning Substation Projects

Public Service, the Staff of the Commission ("Staff'), and the Office of Consumer Counsel ("OCC") agreed in Proceeding No. 14A-1002E that the Company would identify potential new distribution substation sites in rapidly growing areas as part of this report. Below is a preliminary list of conceptual new substation projects under consideration by the Company. This is provided for informational purposes only, and at this time Public Service is not seeking Commission determination of the need for CPCNs for these projects. Because they are conceptual, in-service dates on these projects are TBD.

Long Range Distribution Planning Substation Projects			
Item #	**Substation Project Name**	**Type**	**Approximate location**
35	Superior	115 kV/13.8 kV	Town of Superior
36	Sandy Creek	230 kV/13.8 kV	Arapahoe County, near future Sandy Creek development

G. PROJECTS FOR WHICH PUBLIC SERVICE WILL FILE A CPCN PURSUANT TO DECISION NO. C18-0761

This section describes, and provides updates to, the interconnection facilities and the network upgrades for transmission service associated with the implementation of the Colorado Energy Plan Portfolio ("CEPP"). In its approval of the CEPP by Decision No. C18-0761, the Commission explicitly directed Public Service to file a CPCN application for the proposed Badger Hills Station (now Mirasol Switching Station) and for the additional transmission investment identified in the 120-Day Report. The total transmission investment associated with the CEPP includes: (1) interconnection facilities and (2) network upgrades. The Commission issued Decision No. C20-0648 in Consolidated Proceedings Nos. 19A-0728E and 20A-0063E approving a CPCN for certain network upgrades (i.e., the Greenwood-Denver Terminal 230 kV Transmission Project) and the voltage control facilities associated with the CEPP.

The Company anticipates filing CPCNs for the CEPP interconnection facilities identified below, in 2021. Consistent with Paragraph 51 of Decision No. C20-0648, Public Service will confer with Staff and OCC in advance of filing any CPCN(s) related to these interconnection facilities. Because the Commission has directed, and the Company has committed to filing CPCNs for these interconnection facilities, the projects listed below are only being provided for Commission informational purposes and the Company is not asking for any determination regarding these projects in its 2021 Rule 3206 filing (this filing).

1. CEPP, Interconnection Facilities

This section includes updates to the switching stations (i.e., interconnection facilities) described in the Company's 2020 Rule 3206 Report (Proceeding No. 20M-0005E), which are needed to interconnect generation associated with the CEPP. These interconnection facilities also reflect the changes resulting from the Company's proposed ERP Amendment in Proceeding No. 19A-0530E in which the Company received approval to replace two failed bids originally approved as part of the CEPP (i.e., Bid S430 and Bid X427). These projects were ultimately replaced by Bid 056 and Bid 077 as described below.

a. Mirasol (Formerly Badger Hills) 230 kV Switching Station, (Bid ID X647)

Public Service initially proposed the Badger Hills Switching Station in its ERP proceeding (Proceeding No. 16A-0396E). The Badger Hills Switching Station, now known as the Mirasol Switching Station[5], will be located in Pueblo County to accommodate a new 200 MW Hybrid Generating Facility (200 MW solar plus 100 MW Battery Energy Storage) approved as part of the CEPP. The initial design of the Mirasol Substation will include tapping one Comanche – Midway 230 kV line. The ultimate design of the station will allow future expansion that could tap the

[5] The proposed Badger Hills switching station was renamed "Mirasol" at Pueblo's request.

other 230 kV and 345 kV lines in the corridor and accommodate 345/230 kV transformation. The Mirasol Switching Station will be located 12 miles east of the existing Comanche Substation.

The anticipated in-service date of this project is June of 2022 with an estimated Transmission Cost of $24 million, which is based on updated materials and construction cost estimates.

b. Tundra 345 kV Switching Station, (Bid ID X645)

The project consists of building a new 345 kV switching station tapping the Comanche – Daniels Park 345 kV Line (L 7015). The Tundra 345 kV Switching Station will be located approximately 20 miles from Comanche Substation in Pueblo County. The project is required to interconnect a new 250 Hybrid Generating Facility (250 MW solar plus 125 MW Battery Energy Storage) approved as part of the CEPP. The Tundra 345 kV Switching Station will consist of a 3-breaker ring configuration.

The anticipated in-service date of this project is June of 2022 with an estimated Transmission Cost of $21.4 million, which is based on updated materials and construction cost estimates.

c. New 230 kV Switching Station on the Hartsel - Tarryall 230 kV Line, (Bid ID S085)

The project consists of building a new 230 kV switching station tapping the Hartsel – Tarryall 230 kV Line (L 5995). The project is required to interconnect a new 72 MW Solar Generating Facility approved as part of the CEPP. The new 230 kV Switching Station will have a three-breaker ring configuration.

The requested in-service date of this project is December of 2022 with an estimated Transmission Cost to be determined due to uncertainty around location and scope at this time.

d. New Interconnection at the Existing 230 kV Keenesburg Substation, (Bid ID 090)

This project was placed in-service in September 2020 with an actual Transmission Cost of $0.2 million.

The project consists of a new interconnection at the existing 230 kV Keenesburg Substation, tapping the Keenesburg – Cedar Creek 230 kV generation tie-line. The project interconnects a 169 MW wind generating facility approved as part of the CEPP.

e. New Interconnection at the Existing Boone 230 kV Substation, (Bid ID 035)

As described in the status report filed by Public Service on September 11, 2020 in Proceeding No. 19A-0530E, on September 8, 2020, Bidder 035 indicated that, based on the current economics of the project, the project could no longer be supported at the energy payment rate as bid. The Company subsequently pursued negotiations with back-up bids consistent with the terms of the Settlement Agreement approved in Proceeding No. 19A-0530E and successfully executed a power purchase agreement ("PPA") with Bidder 077 as described in (f) below.

f. New Interconnection at Comanche 230 kV (Bid ID 077)

As described in the status report filed by Public Service in Proceeding No. 19A-0530E on January 11, 2021, the Company successfully executed a PPA on December 22, 2020 for a 200 MW Solar Generating Facility in Pueblo County. The project consists of a new interconnection at the existing 230 kV Comanche Substation.

The expected in-service date is December 31, 2022. The Transmission Cost estimate for this interconnection project has yet to be determined.

g. New Interconnection at the Existing Midway Substation, (Bid ID 056)

As described in the status report filed by Public Service in Proceeding No. 19A-0530E on November 10, 2020, the Company successfully executed a PPA on October 2, 2020 for a new 100 MW Hybrid Generating Facility (100 MW solar plus 50 MW Battery Energy Storage) located in El Paso County. The project consists of a new interconnection at the existing Midway 115 kV Substation.

The anticipated in-service date of this project is May of 2022 with Transmission Costs of $2 million.

2. CEPP, Network Upgrades for Transmission Service

This section includes network upgrades to provide (firm) transmission service associated with the implementation of the CEPP.

The Transmission Service System Impact Study completed for the 100 MW solar plus 50 MW battery Midway project (Bid ID 056), identified single contingency overloads while providing firm transmission service. Replacement of the existing Midway 230/115 kV, 97 MVA transformer with a new 230/115 kV, 280 MVA transformer will be required to mitigate the overloads and support firm transmission service from the proposed Midway facility. The Transmission Costs associated with this upgrade have not yet been determined.

Additional network upgrades for transmission service are <u>not</u> required for the following CEPP projects:

- (Bid ID X647) 200 MW Hybrid Generating Facility (200 MW solar plus 100 MW Battery Energy Storage) at Mirasol Station
- (Bid ID X645) 250 Hybrid Generating Facility (250 MW solar plus 125 MW Battery Energy Storage) at Tundra Station
- (Bid ID S085) 72 MW Solar Generating Facility on the Hartsel - Tarryall 230 kV Line
- (Bid ID 090) 169 MW Wind Generating Facility at 230 kV Keenesburg Substation

Network upgrades for transmission service are not yet determined for the new 200 MW Solar Generating Facility (Bid ID 077) at Comanche Station since the transmission service request studies have not yet commenced.