AMENDED

10-YEAR TRANSMISSION PLAN

For the State of Colorado

To comply with

Rule 3627

of the

Colorado Public Utilities Commission

Rules Regulating Electric Utilities

February 3, 2020

Web addresses updated as of 6/08/2020

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ACRONYMS AND ABBREVIATIONS

Acronym or Abbreviation	Term
2018 Filing	2018 Rule 3627 10-Year Transmission Plan
2020 Plan	2020 10-Year Transmission Plan for the State of Colorado
AQCC	Air Quality Control Commission
ARPA	Arkansas River Power Authority
ATC	Available Transfer Capability
ATCID	Available Transfer Capability Implementation Document
BES	Bulk Electric System
Black Hills	Black Hills Colorado Electric, LLC, d/b/a Black Hills Energy
BHCE	Black Hills Colorado Electric, LLC, d/b/a Black Hills Energy
BHCT	Black Hills/Colorado Transmission
CBM	Capacity Benefit Margin
CBMID	Capacity Benefit Margin Implementation Document
CCOD	City and County of Denver
CCPG	Colorado Coordinated Planning Group
CDOT	Colorado Department of Transportation
CDPHE	Colorado Department of Public Health and Environment
CEII	Critical Energy Infrastructure Information
CEO	Colorado Energy Office
CEP	Clean Energy Plan
CEPP	Colorado Energy Plan Portfolio
City of Raton	Raton Public Service Company
Commission or CPUC	Colorado Public Utilities Commission
Companies	Black Hills, Tri-State and Public Service
Company	Black Hills, Tri-State or Public Service
CPCN	Certificate of Public Convenience and Necessity
CSG	Community Solar Garden
CSU	Colorado Springs Utilities
DSM	Demand-Side Management
EPA	Environmental Protection Agency
EPAct	Energy Policy Act of 2005
ERP	Electric Resource Plan
ERP/APR	Electric Resource Plan Annual Progress Report
ERZ	Energy Resource Zone

Acronym or Abbreviation	Term
Executive Order B 2019 008	The Zero Emission Vehicle Mandate
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GHG	Greenhouse Gas
HB18-1270	Colorado House Bill 18-1270 (the Energy Storage Procurement Act)
HB19-1261	Colorado House Bill 19-1261 (the GHG Reduction Bill)
HVDC	High Voltage Direct Current
IREA	Intermountain Rural Electric Association
KCEA	K.C. Electric Association
KCEC	K.C. Electric Association
kV	Kilovolt
LEV	Low Emission Vehicle
L&R	Load and Resource
LFRTF	Lamar Front Range Task Force
LGIP	Large Generator Interconnection Procedures
LTC	Load Tap-Changing
LTP	Local Transmission Plan
MEAN	Municipal Electric Agency of Nebraska
MW	Megawatts
MVAR	Mega Volt Ampere Reactive
MVEA	Mountain View Electric Association
NECO	Northeast Colorado
NERC	North American Electric Reliability Corporation
NREL	U.S. Department of Energy's National Renewable Energy Laboratory
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OCC	Colorado Office of Consumer Counsel
Order 1000	FERC Order No. 1000 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities
PA	Planning Authority
PNM	Public Service Company of New Mexico
PRPA	Platte River Power Authority
PST	Phase Shifting Transformer

Acronym or Abbreviation	Term
Public Service	Public Service Company of Colorado
PV	Photovoltaic
P-V	Voltage Stability
RCTF	Rush Creek Task Force
REP	Responsible Energy Plan
RES	Renewable Energy Standard
RTO	Regional Transmission Organization
SB07-100	Colorado Senate Bill 07-100
SB18-009	Colorado Senate Bill 18-009 (the Energy Storage Rights Bill)
SB19-236	Colorado Senate Bill 19-236 (the PUC Sunset Bill)
Sierra	Sierra Subregional Planning Group
SLV	San Luis Valley
SOL	System Operating Limits
SPG	Sub-regional planning group
SPP	Southwest Power Pool
SWAT	Southwest Area Transmission Group
SWEP	Southwest Weld Expansion Project
TBD	To Be Determined
TCPC	Transmission Coordination and Planning Committee
TP	Transmission Provider
Tri-State	Tri-State Generation and Transmission Association, Inc.
TRMID	Transmission Reliability Margin Implementation Document
TTC	Total Transfer Capability
WECC	Western Electricity Coordinating Council
Western/WAPA	Western Area Power Administration (also WAPA)

I. Executive Summary

The purpose of transmission planning is to ensure the present and future reliability of the interconnected bulk electric transmission system. Planning is performed to meet customer needs by facilitating the timely and coordinated development of transmission infrastructure projects on a cost-effective and reliable basis. In order to promote an efficient utilization of the transmission system, planning also takes into account drivers such as public policy initiatives, environmental concerns, and stakeholder interests, which are collected via numerous meaningful input opportunities throughout the planning process.

In 2011, the Colorado Public Utilities Commission ("Commission" or "CPUC") adopted Rules 3625 through 3627, which set forth requirements for transmission planning applicable to Commission-regulated utilities. The rules require these utilities to establish a process to coordinate the planning of additional electric transmission in Colorado in a comprehensive and transparent manner. The process is to be conducted on a statewide basis and is to take into account the needs of all stakeholders. This 2020 10-Year Transmission Plan for the State of Colorado ("2020 Plan") is the result of a cooperative effort among Black Hills Colorado Electric, LLC, d/b/a Black Hills Energy ("Black Hills"), Tri-State Generation and Transmission Association, Inc. ("Tri-State"), and Public Service Company of Colorado ("Public Service") (each a "Company" and collectively the "Companies"), and is the fifth 10-Year transmission plan that the Companies have filed under Rule 3627.

Since filing the first 10-Year transmission plan in 2012, the Companies have continued to coordinate the transmission planning process with all Colorado Transmission Providers ("TPs") and interested stakeholders through active outreach efforts and coordinated planning activities in a variety of transmission planning venues. The 2020 Plan is the culmination of a collaborative process and includes transmission facilities that the Companies, individually or jointly, may construct or participate in over the next 10 years in the state of Colorado. The 2020 Plan includes two types of projects.

"Planned Projects" are projects for which the companies generally have a level of commitment such that proposed schedules for completion have been drafted, site control has been established, or the project has received budgetary approvals. These include projects that are required to meet reliability and load growth needs, planned interconnection of new generation, or to meet enacted public policy requirements. "Conceptual Projects", on the other hand, may not have specific in-service dates, and their implementation depends on numerous factors, some of which include forecasted load growth and generation needs, economic considerations, public policy initiatives, and regional transmission development.

The Companies are confident that the 2020 Plan and the individual transmission projects included in the 2020 Plan meet all applicable reliability criteria and do not negatively impact the system of any other TP or the overall transmission system in the near-term and long-term planning horizons. Projects included in the 2020 Plan do not duplicate existing or planned transmission facilities of any other transmission provider in Colorado. Finally, the Companies are confident that the coordination and stakeholder outreach processes described herein effectively have solicited and addressed the interests of stakeholders.

When possible, individual transmission projects have been designed to accommodate the collective needs of multiple TPs and stakeholders. Changes in regulatory requirements, regulatory approvals, or underlying assumptions such as load forecasts, generation or transmission expansions, economic issues, and other utilities' plans may impact this 2020 Plan and could result in changes to in-service dates or project scopes.

Public policy initiatives, such as recent and future federal and local mandates, also may impact the 2020 Plan and the transmission planning process in general. Examples of public policies and legislation potentially impacting the Companies include Colorado House Bill 19-1261, Senate Bill 19-236 (including the "Colorado Transmission Coordination Act"), Senate Bill 19-077, Executive Order B 2019 002, Colorado's

Renewable Energy Standard, Senate Bill 07-100, and the U.S. Environmental Protection Agency's ("EPA") Affordable Clean Energy Rule.

Section II provides background information about the transmission planning process—including coordinated regional and statewide efforts, as well as internal practices of each Company. Sections III and IV of this report provide additional details for these and other projects that the Companies have identified in their transmission planning processes; complete details and supporting information can be found in Appendices D-I. Sections V to VIII address compliance with specific legal, regulatory and technical requirements of Rule 3627 and Federal Energy Regulatory Commission ("FERC") Orders, with an emphasis on stakeholder outreach efforts.

This 2020 Plan identifies 74 significant transmission projects. These projects are listed in Table 1 and shown geographically in Figure 1. Figures 2 and 3 are maps depicting transmission projects in the Denver-Metro area and in Black Hills' 10-Year Transmission Plan, respectively. Larger maps of the state plan showing chronological stages of development are provided in Appendix A. Larger versions of the Denver-Metro and Black Hills maps are provided in Appendices B and C.

Table 1. Significant transmission projects included in the 2020 Plan

Map #	Project Name	In-Svc (1)	Cost (MIL)	BH	TS	PS	Other	Purpose
1	Arequa Gulch 115 kV Capacitor	2018	$0.85	√				R
2	Boyd 230/115 kV Substation Expansion	2018	$10.0				PRPA	R
3	Missile Site – Shortgrass 345kV Transmission	2018	$104.9			√		G
4	Moon Gulch 230 kV Substation	2018	$1.7			√		L
5	Two Basins Relocation Project	2018	$24.1			√		R
6	Bluestone Valley Substation Phase 1	2019	$12.0			√		R
7	Cottonwood 230/115 kV Autotransformer Replacement	2019	$3.0				CSU	R
8	La Junta 115 kV Area Upgrades	2019	$3.9	√				R

Map #	Project Name	In-Svc (1)	Cost (MIL)	BH	TS	PS	Other	Purpose
9	Pawnee-Daniels Park 345 kV	2019	$169.4			√		G,R
10	Portland 115/69 kV Transformer Replacement	2019	$3.7	√				R
11	Sunshine-Telluride Line Uprate	2019	$3.1		√			R
12	Thornton Substation	2019	$21.4			√		L
13	West Station 115 kV Substation Upgrades	2019	$6.5	√				R
14	Ault 345/230 kV XFMR Replacement	2020	$7.8				WAPA	R
15	Boone-La Junta 115 kV Rebuild	2020	$20.9	√				R
16	CEPP Voltage Support	2020	$93.6			√		G
17	Midway KV1A Replacement	2020	$2.0				WAPA	R
18	Nixon-Kelker 230kV Transmission	2020	$0.5				CSU	R
19	NREL Substation	2020	$10.4			√		G
20	Shortgrass – Cheyenne Ridge 345kV Transmission	2020	$62.3			√		G
21	Shortgrass Switching Station	2020	$20.6			√		G
22	Sisson Project	2020	$18.8		√			L
23	Western Colorado Trans Upgrade	2020	$57.2		√			R
24	Williams Creek 230kV Switching Station	2020	$9.1				CSU	G
25	Avery Substation	2021	$10.3			√		L
26	Barker Distribution Substation	2021	$29.8			√		L
27	Del Camino-Slater 115kV Line Uprate	2021	$1.4		√			L,R
28	Desert Cove-Fountain Valley-Midway 115kV	2021	$5.08	√				R
29	Hogback Ranch 115kV Substation	2021	$9.9	√				R
30	Pueblo West 115kV Distribution Sub	2021	$4.5	√				R
31	Salt Creek 115kV Sub	2021	$6.4	√				R
32	South Fowler Substation	2021	$5.1	√				R
33	Airport Memorial-Nyberg 115kV Rebuild	2022	$3.7	√				R
34	Ault-Cloverly 230/115 kV Transmission Project	2022	$66.7			√		L,R
35	Avon-Gilman 115 kV Transmission	2022	$11.4			√		R

Map #	Project Name	In-Svc (1)	Cost (MIL)	BH	TS	PS	Other	Purpose
36	Boone-South Fowler 69/115kV Conversion	2022	$6.6	√				R
37	Burlington-Burlington (KCEA) Rebuild	2022	$0.7		√			R
38	CEPP Switching Station Bid S085	2022	$12.0			√		G
39	CEPP Switching Station Bid X645	2022	$20.0			√		G
40	CSU Flow Mitigation	2022	TBD			√	CSU	R
41	Falcon-Midway 115 kV Line Uprate	2022	$3.8		√			R
42	Greenwood-Denver Terminal 230kV Line	2022	$50.3			√		G,L,R
43	High Point Distribution Substation	2022	$9.0			√		L
44	JG Kalcevik Project	2022	$14.8		√			L,R
45	Mirasol (formerly Badger Hills) Switching Station (CEPP Bid X647)	2022	$12.0			√		G
46	North Penrose 115kV Distribution Sub	2022	$4.5	√				R
47	Titan Distribution Substation	2022	$13.0			√		L
48	Vollmer Project	2022	$7.1		√			L
49	West Station-Greenhorn 115kV Line Rebuild	2022	$4.5	√				R
50	West Station to Hogback 115 kV Transmission Project	2022	$24.0	√				L,R
51	Dove Valley Distribution Substation	2023	TBD			√		L
52	Southwest Weld Expansion Project	2023	$70.0		√			L,R
53	Burlington-Lamar 230 kV	2024	$58.4		√			G,L,R
54	San Luis Valley-Poncha 230 kV #2[2]	2025	$58.0		√	√		R, G
55	Stock Show Distribution Substation	2026	TBD			√		L
56	Bluestone Valley Substation Phase 2	TBD	TBD			√		L
57	Falcon-Paddock-Calhan 115 kV	TBD	$33.4		√			R
58	Glenwood-Rifle 115 kV Transmission	TBD	TBD			√		L,R

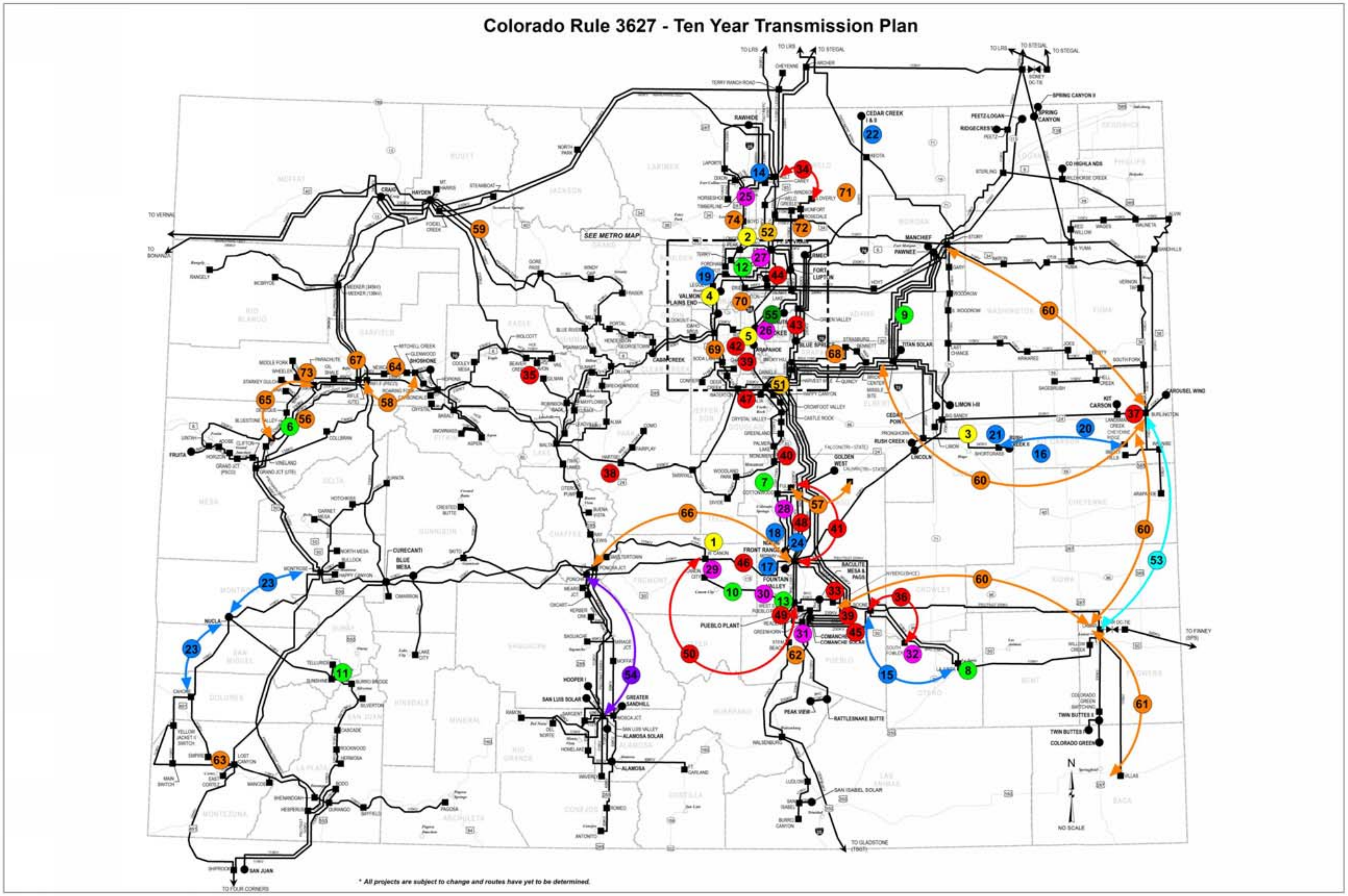
[2] The in-service date and cost for this project are Tri-State estimates and not that of Public Service, though a project may be jointly proposed at some future date.

Map #	Project Name	In-Svc [1]	Cost (MIL)	BH	TS	PS	Other	Purpose
59	Hayden-Foidel-Gore 230 kV	TBD	TBD			√		R
60	Lamar Front Range Transmission	TBD	TBD		√	√		G,R
61	Lamar-Vilas 230 kV Transmission	TBD	TBD		√	√		G
62	Lime Road Delivery Point	TBD	$8.1		√			L
63	Lost Canyon-Main Switch 115 kV	TBD	$22.6		√			L,R
64	New Castle Distribution Substation	TBD	TBD			√		L
65	Parachute-Cameo 230 kV #2	TBD	TBD			√		L,R
66	Poncha – Front Range 230 kV	TBD	TBD			√		G
67	Rifle-Story Gulch 230 kV Transmission	TBD	TBD			√		L
68	Sandy Creek Distribution Substation	TBD	TBD			√		L
69	Solterra Distribution Substation	TBD	TBD			√		L
70	Superior Distribution Substation	TBD	TBD			√		L
71	Weld County Expansion Transmission	TBD	TBD			√		G,R
72	Weld-Rosedale-Box Elder-Ennis 230/115 kV	TBD	TBD			√		L,R
73	Wheeler-Wolf Ranch 230 kV Transmission	TBD	TBD			√		L
74	Wilson Distribution Substation	TBD	$4.0			√		L

Key: R – Reliability, L – Load-serving, G – Generation, TBD – To Be Determined

Note 1: In-service dates are based on best estimates at the time of this filing. Changed needs, load forecasts, permitting activities, timelines for delivery of major equipment, etc. can and will impact project viability and final in-service dates.

Figure 1. Statewide map of significant transmission projects in the 2020 Plan



2018

1. Arequa Gulch 115kV Capacitor (BHCE)
2. Boyd 230/115kV Substation Expansion (PRPA)
3. Missile Site - Shortgrass 345kV Transmission (PSCo)
4. Moon Gulch 230kV Substation (PSCo)
5. Two Basins Relocation Project (PSCo)

2019

6. Bluestone Valley Substation Phase I (PSCo)
7. Cottonwood 230/115kV Autotransformer Replacement (CSU)
8. La Junta 115kV Area Upgrades (BHCE)
9. Pawnee - Daniels Park 345kV (PSCo)
10. Portland 115/69kV Transformer Replacement (BHCE)
11. Sunshine - Telluride Line Uprate (Tri-State)
12. Thornton Substation (PSCo)
13. West Station 115kV Substation Upgrade (BHCE)

2020

14. Ault 345/230kV Transformer Replacement (WAPA)
15. Boone - La Junta 115kV Rebuild (BHCE)
16. CEPP Voltage Support (New, PSCo)
17. Midway KV1A Replacement (WAPA)
18. Nixon - Kelker 230kV Transmission (CSU)
19. NREL Substation (PSCo)
20. Shortgrass - Cheyenne Ridge 345kV Transmission (New, PSCo)
21. Shortgrass Switching Station (New, PSCo)
22. Sisson Project (New, Tri-State)
23. Western Colorado Trans Upgrade (Tri-State)
24. Williams Creek 230kV Switching Station (New, CSU)

2021

25. Avery Substation (PSCo)
26. Barker Distribution Substation (PSCo)
27. Del Camino - Slater 115kV Line Uprate (New, Tri-State)
28. Desert Cove - Fountain Valley - Midway 115kV (New, BHCE)
29. Hogback Ranch 115kV Substation (New, BHCE)
30. Pueblo West 115kV Distribution Sub (New, BHCE)
31. Salt Creek 115kV Sub (New, BHCE)
32. South Fowler Substation (New, BHCE)

2022

33. Airport Memorial - Nyberg 115kV Rebuild (New, BHCE)
34. Ault - Cloverly 230/115kV Transmission Project (PSCo)
35. Avon - Gilman 115kV Transmission (PSCo)
36. Boone - South Fowler 69/115kV Conversion (New, BHCE)
37. Burlington - Burlington (KCEA) Rebuild (Tri -State)
38. CEPP Switching Station Bid S085 (New, PSCo)
39. CEPP Switching Station Bid X645 (New, PSCo)
40. CSU Flow Mitigation (PSCo/CSU)
41. Falcon - Midway 115kV Line Uprate (Tri-State)
42. Greenwood - Denver Terminal 230kV Line (New, PSCo)
43. High Point Distribution Substation (PSCo)
44. JG Kalcevik Project (New, Tri-State)
45. Mirasol Switching Station CEP Bid X647 (formerly Badger Hills Substation) (PSCo)
46. North Penrose 115kV Distribution Sub (New, BHCE)
47. Titan Distribution Substation (PSCo)
48. Vollmer Project (New, Tri-State)
49. West Station - Greenhorn 115kV Line Rebuild (New, BHCE)
50. West Station - Hogback 115kV Transmission Project (BHCE)

2023

51. Dove Valley Distribution Substation (PSCo)
52. Southwest Weld Expansion Project (Tri-State)

2024

53. Burlington - Lamar 230kV (Tri-State)

2025

54. San Luis Valley - Poncha 230kV #2 (Tri-State/PSCo)

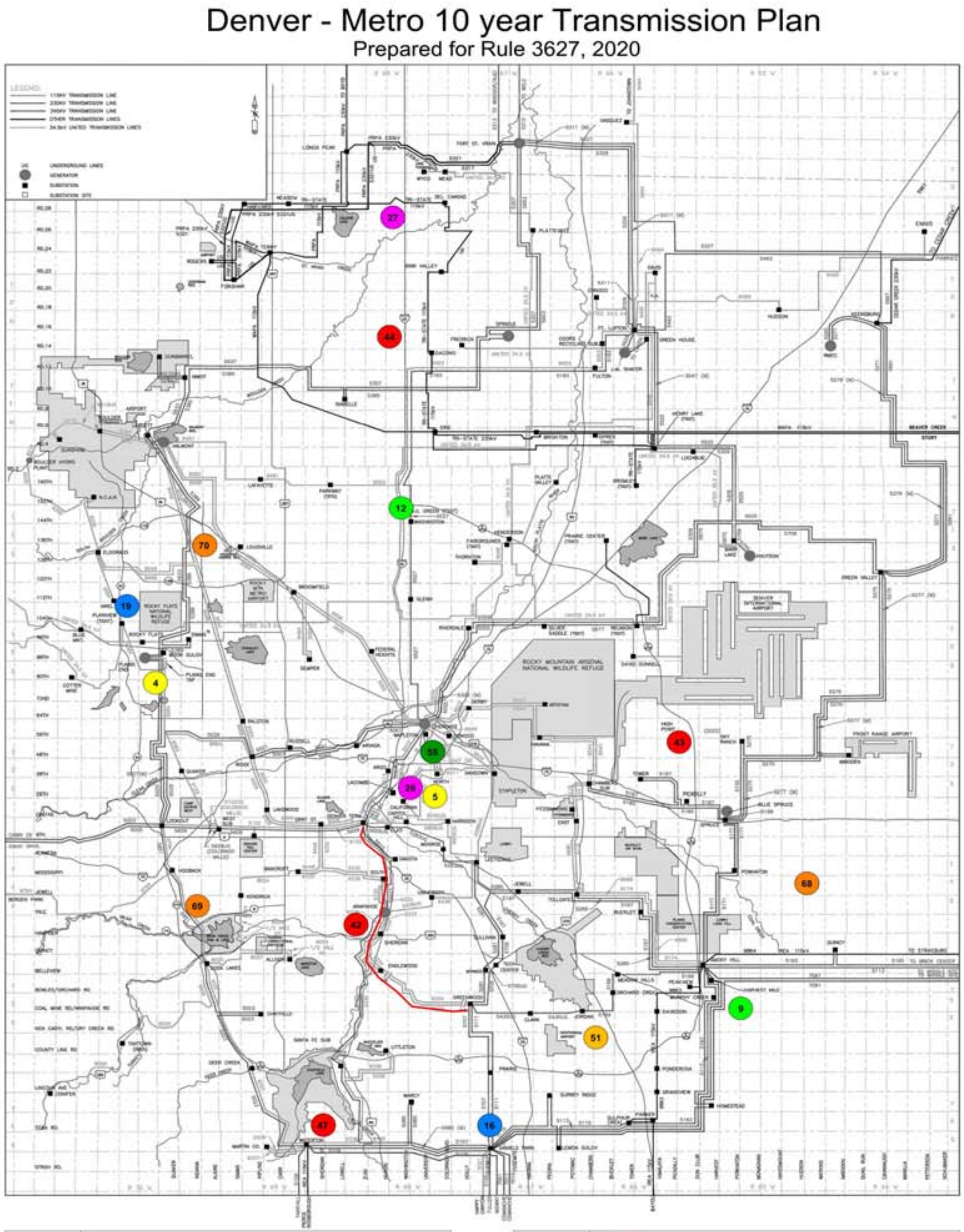
2026

55. Stock Show Distribution Substation (PSCo)

Beyond 2026 or ISD TBD

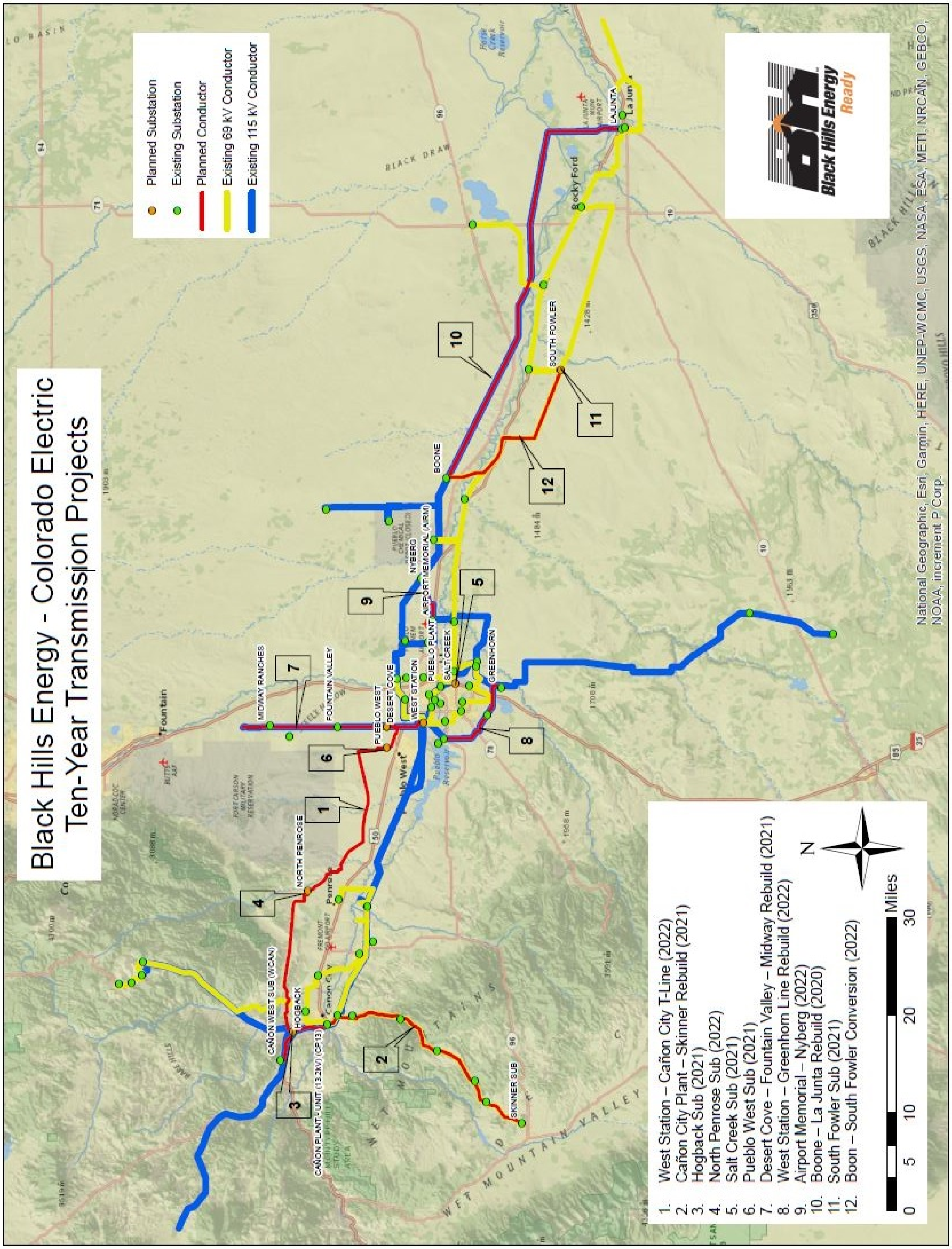
56. Bluestone Valley Substation Phase-2 (PSCo)
57. Falcon - Paddock - Calhan 115kV (Tri-State)
58. Glenwood - Rifle 115kV (PSCo)
59. Hayden - Foidel - Gore 230kV (PSCo)
60. Lamar Front Range (Tri -State/PSCo)
61. Lamar - Vilas 230kV (Tri-State/PSCo)
62. Lime Road Delivery Point (New, Tri-State)
63. Lost Canyon - Main Switch 115kV (Tri-State)
64. New Castle Distribution Substation (PSCo)
65. Parachute - Cameo 230kV #2 (PSCo)
66. Poncha - Front Range (New, PSCo)
67. Rifle - Story Gulch 230kV (PSCo)
68. Sandy Creek Distribution Substation (PSCo)
69. Solterra Distribution Substation (PSCo)
70. Superior Distribution Substation (PSCo)
71. Weld County Expansion (PSCo)
72. Weld - Rosedale - Box Elder - Ennis 230/115kV (PSCo)
73. Wheeler - Wolf Ranch 230kV (PSCo)
74. Wilson Distribution Substation (PSCo)

Figure 2. Denver-Metro map of transmission projects in the 2020 Plan



2018	4 Moon Gulch 230kV Substation (PSCo)
	5 Two Basins Relocation Project (PSCo)
2019	9 Pawnee - Daniels Park 345kV (PSCo)
	12 Thornton Substation (PSCo)
2020	16 CEPP Voltage Support (New, PSCo)
	19 NREL Substation (PSCo)
2021	26 Barker Distribution Substation (PSCo)
	27 Del Camino - Slater 115kV Line Uprate (New, Tri-State)
2022	42 Greenwood - Denver Terminal 230kV Line (New, PSCo)
	43 High Point Distribution Substation (PSCo)
	44 JG Kalcevik Project (New, Tri-State)
	47 Titan Distribution Substation (PSCo)
2023	51 Dove Valley Distribution Substation (PSCo)
2026	55 Stock Show Distribution Substation (PSCo)
TBD	68 Sandy Creek Distribution Substation (PSCo)
	69 Solterra Distribution Substation (PSCo)
	70 Superior Distribution Substation (PSCo)

Figure 3. Pueblo area map of transmission projects in the 2020 Plan



II. Transmission Planning in Colorado

A. Coordinated Planning

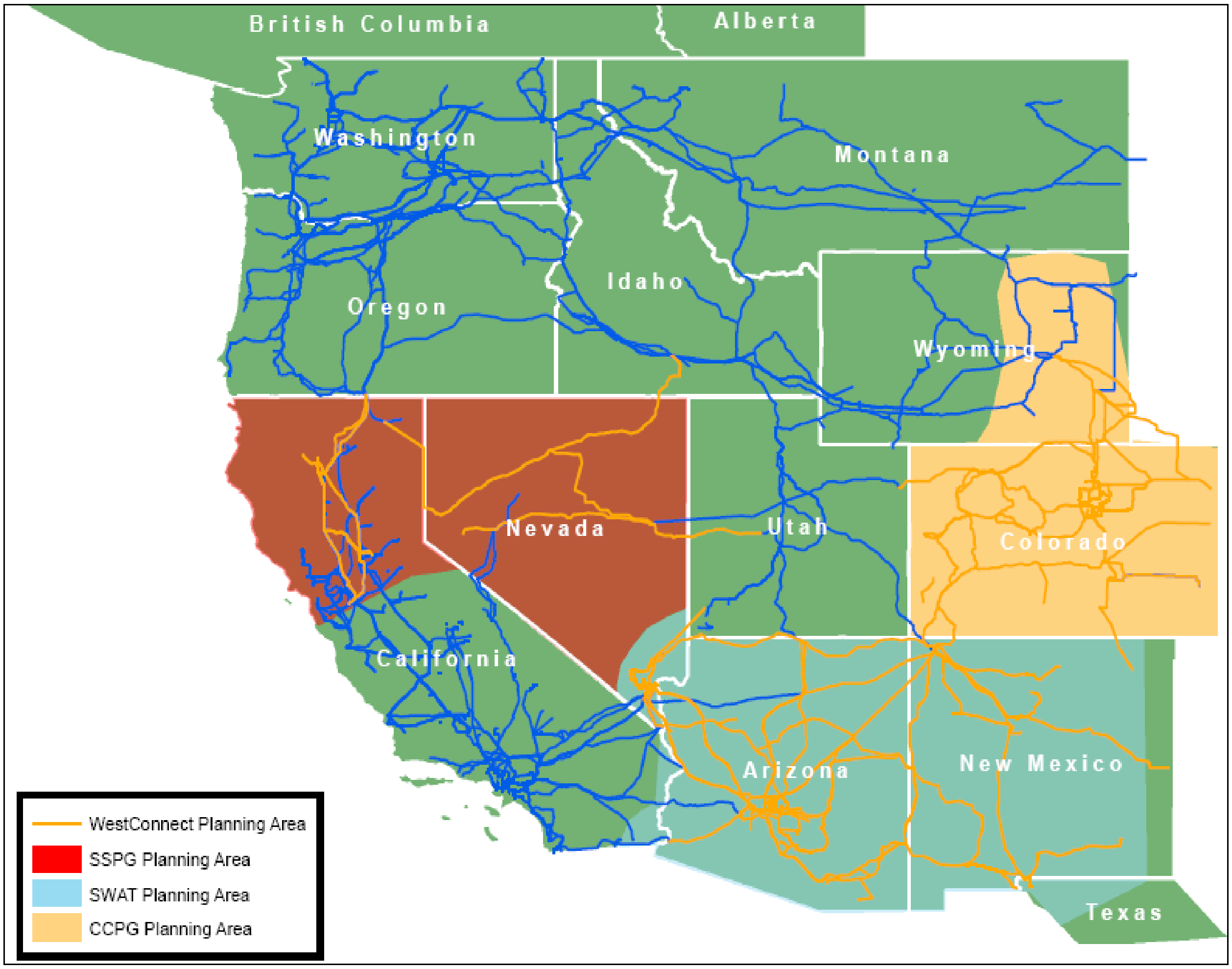
The Companies' transmission planning processes are intended to facilitate the development of electric infrastructure that maintains reliability and meets load growth. Because Colorado does not have a Regional Transmission Organization ("RTO"), each TP in the State is responsible for planning its own transmission system. To ensure that this process is as seamless and efficient as possible, the Companies participate in coordinated transmission planning at regional, sub-regional, and local levels.

The Companies are active members and participants in regional and subregional transmission planning organizations, including the WECC, WestConnect, and the Colorado Coordinated Planning Group ("CCPG"). WECC is the forum responsible for coordinating and promoting Bulk Electric System ("BES") reliability in the entire Western Interconnection.

WestConnect is one of four planning "regions"[3] within WECC established for regional transmission planning to comply with FERC Order No. 1000*, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities* ("Order 1000"). WestConnect includes three sub-regional planning groups ("SPGs"): CCPG, Southwest Area Transmission Group ("SWAT"), and Sierra Subregional Planning Group ("Sierra").

[3] The other three are Columbia Grid, Northern Tier Transmission Group, and the California Independent System Operator.

Figure 4. WestConnect Planning Subregional Group Footprints

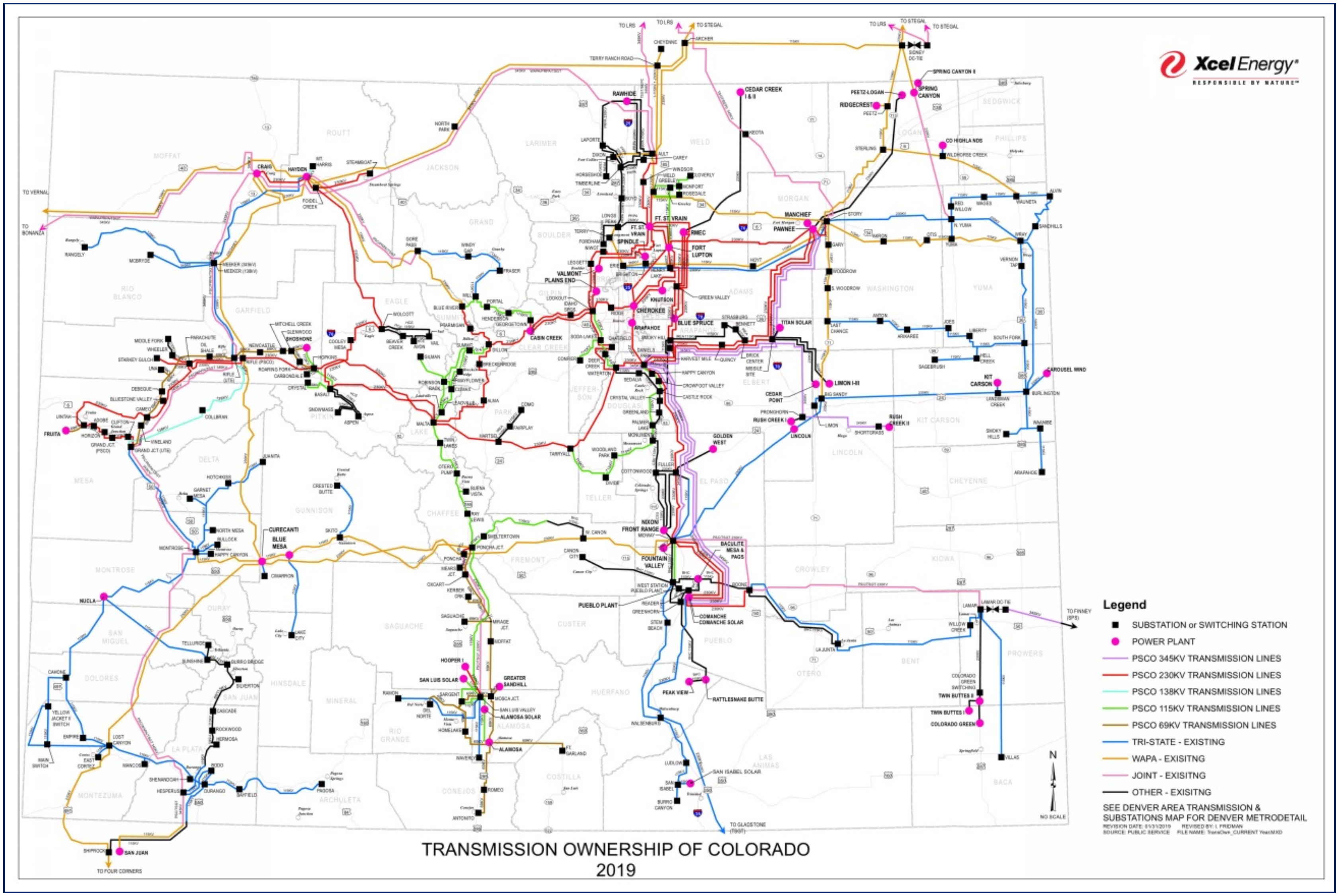


CCPG, which was formed in 1991, is a planning forum that cooperates with state and regional agencies to ensure a high degree of reliability in planning, development and operation of the transmission system in the Rocky Mountain Region. Figure 4 shows the planning areas of the CCPG and other subgroups of WestConnect.

The Companies have a long history of coordinated transmission planning with each other and other Transmission Planners in Colorado. As shown in Figure 5, the Colorado transmission system includes many jointly owned lines. Given the integrated nature and ownership of the transmission grid in Colorado, coordinated transmission planning has been commonplace in Colorado since even before the adoption of Rule 3627.

As part of the Large Generator Interconnection Procedures (“LGIP”), the Companies often coordinate with each other as well as with other TPs in Colorado on the impacts of any proposed generation projects on the transmission system.

Figure 5. Transmission Ownership in the State of Colorado (2019)



Internally, and through WestConnect and CCPG, each Company performs annual system assessments to verify compliance with reliability standards, to determine related system improvements, and to demonstrate adherence to the standards and criteria set forth by North American Electric Reliability Corporation ("NERC") and WECC. Compliance is certified annually.

During the coordinated planning process, a wide range of factors and interests are considered by the Companies, including, but not limited to:

- The needs of network transmission service customers to integrate loads and resources;
- Transmission infrastructure upgrades necessary to interconnect new generation resources;
- The minimum reliability standard requirements promulgated by NERC and WECC;
- Bulk electric system considerations above and beyond the NERC and WECC minimum reliability standard requirements;
- Transmission system operational flexibility, which supports economic dispatch of interconnected generation resources; and
- Various regional and sub-regional transmission projects planned by other utilities and stakeholders.

This comprehensive internal, regional, and sub-regional planning process ensures that transmission plans continue to be carefully coordinated with all TPs in the State of Colorado.

B. Public Policy Issues

In addition to planning for load growth and reliability, Companies must consider proposed and enacted public policy initiatives, such as Colorado House Bill 19-1261, Senate Bill 19-236 (including the "Colorado Transmission Coordination Act"), Senate Bill

19-077, Executive Order B 2019 002, Colorado's Renewable Energy Standard, Colorado Senate Bill 07-100 ("SB07-100"), and the U.S. EPA Affordable Clean Energy Rule. Two of the Companies, Black Hills and Public Service, are subject to the requirements of SB07-100, which requires Colorado's rate-regulated electric utilities to identify areas that have a high potential for beneficial resource development. A discussion of SB07-100 and other public policy-related planning is included in Section V.

Colorado's Seventy-Second General Assembly enacted climate-action legislation in the 2019 Regular Session. The legislation will transition the state toward a clean-energy, low-carbon economy. The legislation establishes public policy requirements applicable to transmission planning for the 10- and 20-year periods of this Rule 3627 Report. We describe the applicable parts of this legislation for Colorado's transmission infrastructure, as follows:

<u>Senate Bill 19-236 ("the PUC Sunset Bill")</u>

The primary purpose of this bill is to reauthorize the CPUC, by appropriations, for a seven-year period to September 1, 2026. Reauthorization is required by the sunset process. Additionally, the bill carries numerous requirements for utilities and the CPUC to achieve an affordable, reliable, clean electric system. Of these requirements, four are viewed as significant drivers for transmission development in Colorado.

1. <u>Clean Energy Plan ("CEP")</u>

Senate Bill 19-236's CEP requirement is only mandatory for retail utilities providing electric service to more than 500,000 customers. *See* C.R.S. 40-2-125.5. While Public Service is the only public utility subject to this mandatory requirement to formulate a CEP, the legislation provides that other public utilities may "opt in" to CEP regulation upon notification to the Commission. However, the statute expressly excludes municipally owned utilities from CEP regulation. Public utilities that are subject to the CEP requirement must include a CEP as part of the first Electric Resource Plan ("ERP") the public utility files after January 1, 2020. The PUC determines whether a CEP/ERP, as filed, is in the public interest.

A CEP seeks to reduce the qualifying retail utility's carbon dioxide emissions associated with electricity sales to the qualifying retail utility's electricity customers by 80 percent from 2005 levels by 2030. Further, a CEP seeks to achieve providing a qualifying retail utility's customers with energy generated from 100% clean energy resources by 2050.

Clean energy resources generate or store electricity without emitting carbon dioxide into the atmosphere. Clean energy resources include, without limitation, those generating resources deemed eligible energy resources under the state's Renewable Energy Standard ("RES") pursuant to C.R.S. § 40-2-124(1)(a). CEP activities that may be undertaken to meet the CEP targets under Senate Bill 19-236 include retirements of existing generation facilities, changes in system operations, or other necessary actions to achieve the reduction targets.

A CEP must ensure rate stability for customers served by the utility. Senate Bill 19-236 provides that the "Commission shall establish a maximum electric retail rate impact of 1.5 percent of the total electric bill annually for each customer for implementation of the approved additional clean energy plan activities" through at least 2030 through a CEP revenue rider to afford customers certainty of this maximum rate impact.

New transmission development for a CEP will be reviewed by the PUC under existing transmission planning processes and cost recovery, namely: Rule 3206, Rule 3627, SB07-100, and the Transmission Cost Adjustment. Senate Bill 07-100 Energy Resource Zones will apply to the beneficial resources required for CEP compliance.

In summary, a CEP will present significant drivers for transmission planning, namely:

- New interconnection facilities for clean energy resources;
- Decommissioning, or redevelopment, of existing transmission facilities associated with the potential for accelerated fossil-fuel retirements.

Transmission planning must enable a transition from plant retirements to new generating resources that ensures reliability and resiliency.

2. Cost of Carbon

Senate Bill 19-236 additionally requires public utilities to perform a "cost of carbon" analysis under certain circumstances. *See* C.R.S. §40-3.2-106. This "cost of carbon" analysis requirement applies to the following categories of proceedings: ERPs or any utility plan or application that considers or proposes the acquisition of new electric generating resources or the retirement of existing utility generation; proceedings pertaining to RES; electric demand-side management proceedings; and plans or applications for transportation electrification or other forms of beneficial electrification. The cost of carbon dioxide emissions is based on the social cost of carbon dioxide developed by the federal government. This equals $46 per short ton starting in 2020 and escalates thereafter.

In ERP proceedings, the cost of carbon dioxide emissions must apply to the evaluation of all existing electric generation resources and to any new resources evaluated or proposed as part of the resource modelling. The statute prescribes modeling and analysis steps for evaluating resource portfolios, with and without the cost of carbon dioxide.

In summary, cost-of-carbon planning will result in similar requirements as a CEP for transmission planners, namely: new interconnection facilities and accelerated decommissioning, or redevelopment, of existing transmission facilities, which together may serve to reduce carbon intensity of the electric utility sector while ensuring reliability and resiliency of the grid.

3. Colorado Transmission Coordination Act

The Colorado Transmission Coordination Act, C.R.S. § 40-2.3-101 *et seq.*, requires the CPUC to open an investigatory proceeding on the potential costs and benefits of participation by Colorado's electric public utilities in a centralized market: specifically, an energy imbalance market, a regional transmission organization, a power pool, or a joint tariff. The statutory timeline is prescribed as follows:

(1) On or before July 1, 2021, the CPUC shall hold a public comment hearing to consider whether electric public utilities should participate in an energy imbalance market, regional transmission organization, power pool, or joint tariff.

(2) On or before December 1, 2021, the CPUC shall issue a decision determining whether participation in an energy imbalance market, regional transmission organization, power pool, or joint tariff is in the public interest.

(3) On or before July 1, 2022, if the CPUC determines that electric utility participation in an energy imbalance market, regional transmission organization, power pool, or joint tariff is in the public interest, the CPUC shall direct electric utilities to take appropriate actions and conduct proceedings the CPUC deems appropriate to pursue participation in an energy imbalance market, regional transmission organization, power pool, or joint tariff.

Adoption of a centralized market is uncertain. If adopted and implemented, a centralized market could be transformative but is highly dependent on the form and function of the determined market design. A centralized market has the potential to change the locational mix of generating resources and provide congestion relief on the grid through market operations. While relieving congestion is a driver of transmission planning now, a centralized market also may give a market price signal at zones or nodes along the grid. These market prices are known as "Locational Marginal Price" or "LMP". An LMP is a market-clearing price that includes the energy charge, a congestion charge, and transmission system losses. High LMPs at zones/nodes mean more transmission congestion. LMPs may drive investment needs for, and locations of, new transmission facilities to relieve congestion.

4. Wholesale Electric Coops and Resource Planning

Senate Bill 19-236 additionally directs the Commission to promulgate new rules that require wholesale electric cooperatives to submit an application for approval of an integrated or ERP. *See* C.R.S. § 40-2-134. In developing such rules, the Commission must consider, among other factors determined by the Commission, whether wholesale electric cooperatives: serve a multistate operational jurisdiction; have a not-for-profit ownership structure; and have a resource plan that meets the energy policy goals of Colorado.

The Commission issued a Notice of Proposed Rulemaking on July 31, 2019, addressing this statutory requirement and proposing an electric resource planning process applicable to wholesale electric cooperatives. Final rules are pending.

Consistent with this rulemaking, Tri-State expects to continue to interconnect new renewable facilities while retiring certain legacy facilities, and anticipates making transmission improvements as appropriate to accommodate these changes.

House Bill 19-1261 (“the GHG Reduction Bill”)

House Bill 19-1261 requires the Air Quality Control Commission (“AQCC”) to promulgate rules and regulations for statewide greenhouse gas (“GHG”) pollution abatement. *See* C.R.S. § 25-7-105.

Because these rules and regulations will target statewide GHG abatement from all sources, multiple sectors of Colorado’s economy will be considered for compliance (transportation, electric generation, industrial manufacturing, etc.). The statewide goals are, at a minimum, a 26 percent reduction in statewide GHG pollution by 2025, a 50 percent reduction in GHG pollution by 2030, and a 90 percent reduction in GHG pollution by 2050 measured relative to statewide GHG pollution levels.

It is anticipated that the AQCC will consider opportunities to incentivize renewable energy resources, issues related to the beneficial use of electricity to reduce GHG, and whether program design could enhance the reliability of electric service.

For transmission planning, the GHG Reduction Bill presents the potential for new load growth and/or changing demand levels and characteristics (beneficial electrification), and shifting generation resources and locational mix (renewable energy and clean-energy adoptions).

Senate Bill 19-077 (“the Electric Vehicles Bill”)

Statutory provisions enacted through Senate Bill 19-077 in C.R.S. §§40-1-103.3, 40-3-116, and 40-5-107 may expand electric vehicle infrastructure in Colorado. Charging ports and fueling stations are presently operated by third parties and as non-regulated services of public utilities. Senate Bill 19-077 authorizes utility ownership of electric vehicle charging infrastructure. The bill enables a regulatory approval process for electric utilities to invest in charging facilities and provide incentive rebates; thus, the investments and rebates may earn a return at the utility’s authorized weighted-average cost of capital. Where approved, the costs for the investments and rebates may be recovered from all customers of the electric utility similar to recovery of distribution system investments. Natural gas public utilities may provide fueling stations for alternative fuel vehicles as non-regulated services only.

The regulatory process for electric utilities will commence by May 15, 2020, and every three years thereafter, with the filing of a transportation electrification plan application by each jurisdictional utility. The application filing will request Commission authorization of a proposed transportation electrification program in the utility's certificated service territory; specifically, regulated activities and capital spending for electric vehicle charging facilities, electric vehicle make-ready infrastructure investments, and associated electrical equipment. The transportation electrification program may include community-based, multifamily charging infrastructure, car share programs, and electrification of public transit. The regulatory process will consider impacts on low-income customers, and access by low-income, moderate income, and underserved communities. The legislation provides that the retail rate impact from the development of electric vehicle infrastructure must not exceed one-half of 1 percent of the total annual revenue requirements of the utility. The legislation specifies that in evaluating the retail rate impact, the Commission "shall consider revenues from electric vehicles in the utility's service territory."

Widespread deployment of electric vehicles will represent load growth for transmission planning requirements within the 10-year period of this report. Further, adoption of electric vehicles will provide benefits to the grid. With charging electric vehicles essentially acting as energy storage, there may be an ability to integrate variable renewable resources and off-peak generation.

<u>House Bill 18-1270 ("the Energy Storage Procurement Act")</u>

House Bill 18-1270 directs the Commission to develop a framework to incorporate energy storage systems in utility procurement and planning processes. *See*

C.R.S. § 40-2-201, *et seq*. The legislation broadly addresses resource acquisition and resource planning, and transmission and distribution system planning functions of electric utilities. Energy storage systems may be owned by an electric utility or any other person.

House Bill 18-1270 required the Commission to adopt rules for procurement and planning by February 1, 2019, to create conditions under which the procurement or ownership of energy storage systems by an electric utility will provide systemic benefits. These benefits include increased integration of energy into the grid; improved reliability of the grid; a reduction in the need for increased generation during periods of peak demand; and, the avoidance, reduction, or deferral of investment by the electric utility.

Decision C18-1124 in Proceeding No. 18R-0623E, mailed on December 12, 2018, adopted permanent rules in 4 *Code of Colorado Regulations* (CCR) 723-3. The rule requirements on transmission planning are relevant to this 10-year planning period.

<u>Governor Jared Polis Administration's "Roadmap to 100% Renewable Energy by 2040 and Bold Climate Action"</u>

On May 30, 2019, Governor Polis unveiled a roadmap to 100% renewable energy by 2040 and bold climate action. The roadmap seeks to transition the state of Colorado to 100% renewable energy by 2040. Toward this end, the roadmap has seven components, namely:

1. Grow green jobs and save consumers money.
2. More zero emission vehicles and commuting options.
3. Support local commitment to 100% renewable energy.
4. Modernize the Public Utilities Commission.
5. Promote energy efficiency.
6. Move toward zero emissions buildings.
7. Ensure a just and equitable transition for all of Colorado.

A transition to 100% renewable energy would have a significant impact on transmission planning in the 10-year period with load growth. Specifically, electrification of transportation will represent load growth; notably, the Governor's plan strives for 940,000 zero emission vehicles by 2030 and $14 million of transit bus fleet conversions. Similarly, electrification of buildings will represent load growth as space heating and manufacturing needs shift from direct fossil fuels to electricity. The Governor's plan has three financing programs for residential and commercial building improvements: C-Pace, RENU, and the Colorado Clean Energy Fund. In FY2019, approximately $30 million was financed by C-Pace and RENU alone.

Executive Order B 2019 008 ("the Zero Emission Vehicle Mandate")

On January 17, 2019, Executive Order B 2019 002 – Supporting a Transition to ZEV –was issued by Governor Polis. Four areas are directed in the Executive Order to further the state toward a higher electric vehicle market share:

1. Creates a transportation electrification workgroup composed of 17 members, appointed by the Governor. The members represent state agencies and offices. The workgroup will develop, coordinate, and implement state programs and strategies for transportation electrification with annual reports to the Governor.

2. Directs the Colorado Department of Public Health and Environment ("CDPHE") to develop rules for a Colorado Zero Emission Vehicle Program pursuant to Colorado's authority under section 177 of the federal Clean Air Act, 42 U.S.C. § 7507.

3. Revises the spending for the remaining funds available in Colorado's $70 million VW Beneficiary Mitigation Plan for electrification of transportation, including transit buses, school buses, and trucks. Furthermore, if additional

settlement or lawsuit funds are received by Colorado, those funds will assist consumers' transition to ZEVs.

4. Directs the Colorado Department of Transportation to develop a department-wide ZEV and clean transportation plan.

In compliance with the Executive Order, the Air Quality Control Commission ("AQCC") adopted a ZEV rule on August 16, 2019. The rule is codified at 5 *CCR* 1001-24, Part C. For the 2023 vehicle model year, a specified percentage of vehicles *offered for sale* in Colorado must be ZEV. The percentage shall be consistent with California Code of Regulations, Title 13, Section 1962.2. The percentage is more than 5 percent zero emission vehicles by 2023 and more than 6 percent zero emission vehicles by 2025. The vehicles covered by the ZEV rule are passenger car and light-duty trucks.

The ZEV rule follows the Low Emission Vehicle ("LEV") rule adopted by AQCC on November 16, 2018. The rule is codified at 5 *CCR* 1001-24, Part B. The LEV rule complied with Executive Order B 2018 006 issued by Governor John Hickenlooper on June 18, 2018. For the 2022 vehicle model year, sales of passenger cars, light-duty trucks, medium-duty passenger vehicles or medium-duty vehicles must meet the LEV III Criteria emissions and GHG emissions codified by California Code of Regulations, Title 13, Sections 1961.2 and 1961.3, respectively. The proposed ZEV program will reduce total GHG emissions by 3.5 million short tons cumulatively by 2030.

For transmission planning, electrification of transportation as directed in the ZEV rule will represent load growth. However, in the near term, there are regulatory uncertainties. The ZEV rule is facing federal challenges by the Administration of President Donald Trump under authority of the Clean Air Act.

Senate Bill 18-009 ("the Energy Storage Rights Bill")

Senate Bill 18-009, enacted in C.R.S. § 40-2-130, protects the rights of Colorado electricity consumers to install, interconnect, and use energy storage systems on their property without the burden of unnecessary restrictions or regulations and without unfair or discriminatory rates or fees. In particular, Senate Bill 18-009 prohibits electric utilities from requiring additional customer-sited meters to monitor the energy storage system where a single net energy meter is installed (with exceptions for certain large energy systems). Moreover, Senate Bill 18-009 ensures that statutory net metering, as provided for in C.R.S. § 40-2-124, is neither altered nor superseded.

Senate Bill 18-009 requires the CPUC to adopt conforming rules. In rulemaking Proceeding No. 19R-0096E, the CPUC has proposed additions and amendments at Rule 3850 (Interconnection Procedures and Standards) to *inter alia* implement Senate Bill 18-009. Notably, a proposed definition for "distributed energy resource" has replaced the former definition for "small generating facility". Distributed energy resources, or DERs, is proposed to be defined as customers' sources of electric power, including retail renewable distributed generation, other small generation facilities, and energy storage systems. Distributed energy resources, or DERs, will be subject to PUC-approved interconnection procedures upon adoption of final rules.

C. Emerging Issues

1. Wildfire Risk Mitigation

One only needs to look to California to see the impact a wildfire can have on the electric system and community at large. Given that, the companies believe that investment in wildfire mitigation and grid resiliency is the most prudent course of action to moderate the risks associated with extreme weather events. Wildfire mitigation efforts have been and will continue to be centered on long-term investments in projects targeted at enhancing grid resiliency, expanding vegetation management, and accelerating system hardening and equipment maintenance throughout the companies' service territories.

2. Energy Storage and Non-wires Alternatives

Non-wires alternatives to address capacity needs and reliability constraints related to load growth is an emerging topic for consideration during transmission planning. As such, an additional work group at CCPG, the Energy Storage Work Group (ESWG), has been created to analyze the benefits and challenges for energy storage and other non-wire alternative technologies. Studies may include geo-targeted energy efficiency, demand-side management, demand response, distributed generation, energy storage, and potentially other technologies. The first meeting for the ESWG was held on January 23, 2020.

3. Distributed Energy Resources (DER)

The increase of customer-sited DER may alter transmission system requirements. Most utilities have been able to model customer DER primarily on distribution systems as net load. Increasing DER penetration presents new challenges with modeling and operation of distribution and transmission systems. DERs also may present opportunities to address load growth and provide resiliency, if planned correctly. DERs tend to be more expensive than larger-scale generation options, and so cost-effectiveness will be a factor in the growth of DERs over time. It will be important to understand policies and consider investments that may be needed in the 10-year horizon.

4. Grid Resiliency with Inverter-Based Resources

The influx of inverter-based resources combined with conventional power plant closures has raised concerns of grid resiliency. The Blue Cut Fire (2016) and Canyon 2 Fire (2017) in California triggered approximately 900 MW and 1200 MW, respectively, of solar PV generation to cease generation during transmission system faults. These events and other system observations have led NERC to develop Reliability Guidelines to assist utilities and manufacturers in maintaining a resilient grid. Recent Reliability Guidelines include the following:

- Integrating Inverter-Based Resources into Low Short Circuit Strength Systems (December 2017)
- BPS-Connected Inverter-Based Resource Performance (September 2018)
- Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources (September 2019)

At the regional level, WECC's Studies Subcommittee has a Change to System Inertia with High Renewable Implementation Task Force (SITF) evaluating the reliability impacts on the Western Interconnection as conventional resources are retired during increased implementation of inverter-based resources. The companies believe that it will be important to understand and apply the Reliability Guidelines as they are developed, as well as participate in regional study efforts to ensure proper analysis is performed to maintain grid resiliency.

III. Company Plan Narratives

A. Black Hills 10-Year Plan Overview

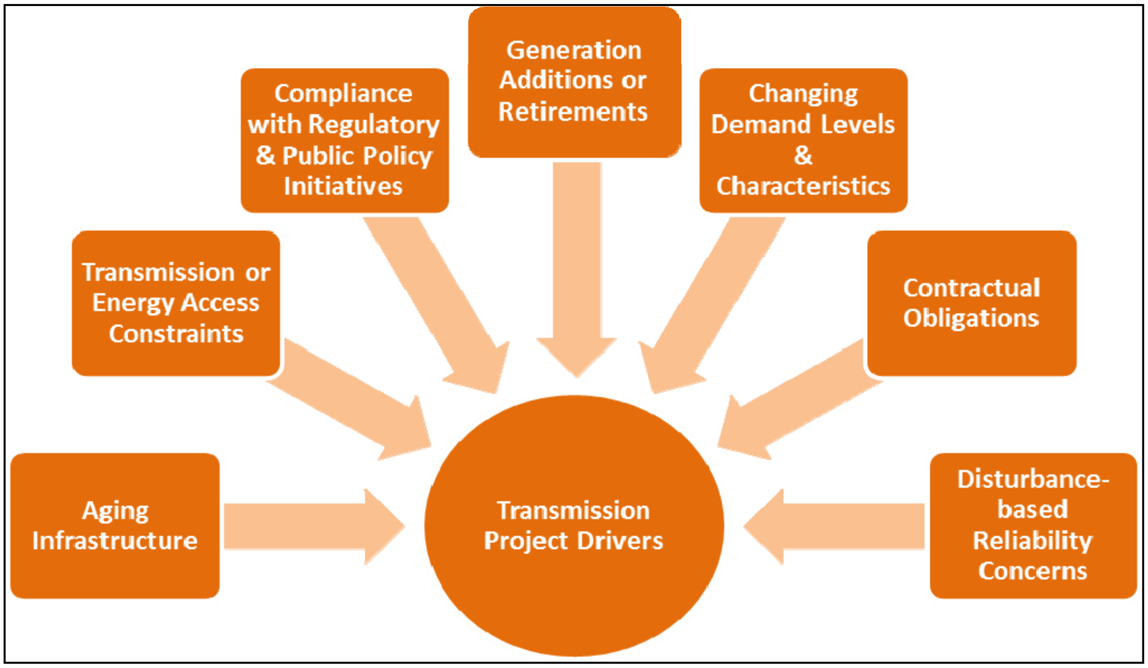
1. Black Hills Service Territory

Black Hills Colorado Electric, LLC, a division of Black Hills Corporation, serves over 98,000 customers in south-central Colorado. The counties served are parts of Crowley, Custer, El Paso, Fremont, Otero, Pueblo, and Teller. Twenty-one communities are served, and of these, the largest communities are Pueblo, Cañon City, and Rocky Ford.

The Black Hills planning process emphasizes education, participation, and coordination, with the ultimate goal of contributing to the development of an optimal long-term road map for transmission development in Colorado, consistent with Rule 3627.

Throughout its transmission planning process, Black Hills considers a number of variables and inputs, the first of which is a specific need or set of needs that drive the development of a certain project. Figure 6 shows a selection of needs that commonly give rise to projects within the Company's planning horizon.

Figure 6. Needs that Drive Transmission Development



Needs may arise from a single entity, or they may coincide with the needs of multiple entities, in which case a joint project may be appropriate. Once a need has been identified, Company planners begin searching for a solution. As solution alternatives are developed, the following considerations may come into play:

- Potential of each alternative to augment or inhibit potential future projects
- Cost of implementation and availability of project funding
- Required implementation schedule
- Environmental and societal impacts
- Project life expectancy
- Tangible benefits to customers
- Geographic and physical constraints
- Ability to integrate with existing and planned transmission projects
- Impact to telecom, transportation, and other energy-related networks

Black Hills transmission planners, through coordination with the stakeholder community, evaluate the weight of the above considerations to determine the best overall solution to the identified need, ensuring that the solution is financially prudent, publicly acceptable and physically feasible. Often a small subset of these factors will comprise a majority of the justification for a project.

Because communication and stakeholder participation is critical at all stages of planning, Black Hills performs its planning process on an annual basis in an open, transparent, coordinated and non-discriminatory fashion to ensure the opportunity for direct participation is offered to all stakeholders. Consistent with FERC Order Nos. 890 and 1000, Black Hills promotes participation in the planning process to all interested parties, and coordinates study efforts and results with other utilities as well as regional planning organizations such as West Connect, CCPG, and various groups within WECC.

Planning reliability studies are conducted annually to satisfy NERC and WECC requirements. Additional studies are performed as necessary to address specific purposes including, but not limited to, transmission service requests, generator interconnections, transmission interconnections, load interconnections and transfer capability assessments. This process and related discussions are subject to FERC's Critical Energy Infrastructure Information ("CEII") procedures.

Black Hills planners employ software models representative of the transmission system during the timeframe of interest, including current load and resource information, existing and planned infrastructure, service commitments, facility ratings and parameters, valid disturbance events, and any operating constraints to be observed. Additionally, all guidelines, requirements and applicable criteria, as well as 10-Year load and resource projections (submitted annually by network customers), are reviewed and included in the study plan. These study models allow planners to identify conditions and timeframes during which the transmission system will or will not satisfy all reliability and economic requirements.

If a planning study identifies a deficiency in transmission system performance, various mitigation options are evaluated to determine an optimal solution to meet the long-term needs of all affected parties. Evaluation of each potential project is coordinated with interested stakeholders and neighboring transmission providers to avoid duplication, minimize impacts and the likelihood of unmet obligations, and maximize the overall benefit of a project.

Routine planning is conducted for a wide range of scenarios to evaluate the performance of the transmission system over a 10- to 20-year period. In a given study year, viable system upgrades and transmission initiatives are compiled to create the Black Hills 10-Year Local Transmission Plan, which is evaluated annually and updated as needed to reflect ongoing project needs. Potential changes in reliability requirements, planned generation, transmission, load growth, and regulations require the build-out of a flexible, robust transmission system that meets customer needs under a wide range of foreseeable circumstances within the planning horizon.

2. Black Hills Projects

A. Renewable Advantage (200 MW)

On November 22, 2019, Black Hills Colorado Electric, LLC filed an application at the Commission to amend its 2016 Electric Resource Plan with a competitive solicitation for up to 200 MW of renewable energy and energy storage. The competitive solicitation is known as Renewable Advantage. The application was docketed in Proceeding No. 19A-0660E.

The Company's expected load and resource balance was determined in Phase I of the 2016 ERP and completed in January 2017. There have been no significant changes to the load and resource balance. The Company has no material need for new capacity through December 31, 2023.

This notwithstanding, the Company's indicative analysis provides that procuring energy from renewable resources and/or energy storage, with an in-service date no later than December 31, 2023, may produce significant benefits for customers. The benefits are energy fuel cost savings and emission reductions beyond the state's Renewable Energy Standard (30% of retail electricity sales by 2020). The fuel cost savings will be implemented through the ECA rate mechanism. The procurement will have no negative impact to the RESA fund. The emission reductions could bring the Company's service territory to approximately 55-65% renewable.

The Company's indicative analysis is based, in part, on modeling of recent bid price results from PSCo's renewable competitive solicitation. The PSCo renewable competitive solicitation was held from July 1 through August 1, 2019. The median bid price was $24.00 MWh for Solar PV and $36.30 MWh for SolarPV+Storage. Black Hills Energy has modeled these median bid prices for a 200 MW generic resource, showing customers savings in every year of the life of the generic resource.

An important consideration for any procurement of renewable or storage resources under Renewable Advantage will be to minimize any transmission cost impacts to customers.

The Company has identified five existing substations where minimal or no upgrades to the broader network transmission system are expected with the addition of 200 MW. While the Company has not specifically studied these locations, there is a high degree of confidence that these five substations can accommodate the new resources with lesser amounts of upgrades and costs. The preferred locations for interconnection are:

1. West Station Substation
2. Baculite Mesa Substation
3. Nyberg Substation

4. Boone Substation
5. Midway Substation

Further, it is appropriate to limit the addition of new renewable and storage resources to 200 MW for two primary reasons. First, a contingency scenario indicates that forcing any amount beyond 200 MW on a single 222 MVA-rated line, or on a single 120 MVA- or 160 MVA-rated line, would require significant spending for line rebuilds, system improvements, and/or generation curtailment to successfully interconnect the project. Thus, 200 MW is a prudent approach for mitigating transmission cost impacts. Second, the Company's transmission planning only studies a moment in time and not real-time (minute-to-minute) operating situations that can occur when variable generation ramps quickly. As the Company's renewable penetration increases, it will be increasingly difficult to balance the Company's generation and load in real-time. The 200 MW bid amount for the Renewable Advantage is about equal to the Company's minimum system load, a prudent limit for balancing the Company's generation and load in real-time conditions.

B. Transmission Projects

Black Hills' load growth has increased over the past couple of years, driven primarily by large industrial load expansions as well as some commercial load growth. The Black Hills projects included in the 2020 Plan largely reflect the continued strategy of infrastructure upgrades of additions to enhance reliability. Since most of Black Hills' projects are reliability-driven equipment replacements or upgrades, the focus on best-cost considerations was narrowed as appropriate.

In the 2020 Plan, which was the result of an open and coordinated planning approach on regional, sub-regional and local levels, Black Hills documents a procedure to address foreseeable local reliability, integrity and load service issues. Detailed project information can be found in Appendix D.

Since the filing of the 2018 10-Year Plan, Black Hills has completed three projects: Arequa Gulch 115kV Capacitor, Portland 115/69 kV Transformer Replacement, and West Station 115 kV Substation Upgrades. Black Hills identified 11 planned projects within the upcoming 10-year planning horizon that represent $89.52 million in capital expenditures between 2020 and 2023. The projects were identified to increase reliability within Black Hills' network transmission system, to support voltage, and to meet the requirements associated with expected load growth and generation development. The reliability-driven projects are required under various NERC Reliability Standards to address anticipated system performance issues. The projects in this section were coordinated with stakeholders and neighboring entities to ensure the best solution is achieved while avoiding duplication of facilities.

Planned projects are categorized according to the three distinct geographic areas within Black Hills' Colorado service territory.

Cañon City area

Three projects, shown in Table 2, address reliability and integrity concerns in the Cañon City area. Local load growth has resulted in the need for additional capacity in the area, as well as local voltage support. A new transmission line into the area and a substation rebuild will improve load service and operational flexibility.

Table 2. Cañon City area projects included in the Black Hills 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
West Station – Hogback Transmission Line[4]	1/2022	$24.00	Not required

[4] This line also is known as the Southern Colorado Reliability Upgrade Project.

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
115/69 kV Hogback Ranch Substation Build	9/2021	$9.90	Not required
115kV North Penrose Distribution Substation	1/2022	$4.5	A planned project included in the 2018 Rule 3206 filing (Proceeding No. 18M-0005E)

The Black Hills planning process identified these projects as solutions for expected concerns regarding reliability and anticipated load growth in the Cañon City area. The primary driver of the West Station – Cañon City Transmission Line was to increase the reliability of Black Hills' transmission system feeding Cañon City and the surrounding area. Load growth in the Cañon City area has led to reliability concerns following the loss of the two transmission lines connecting that area to the Pueblo part of the Black Hills system. To mitigate these concerns, several options were considered. The West Station – Cañon City 115 kV Transmission Line build is set to rectify the burden of load growth in the area. The new connection also enables the future replacement of stressed transmission lines at a greatly reduced operational risk.

The Hogback Ranch project provides the added benefit of adding a 115/69 kV source near the existing North Cañon 69 kV substation. This will offload the existing Cañon City transformer and add operational flexibility to the local 69 kV system. The new source may provide future improved backup service to the Cripple Creek area via the normal open 69 kV line for emergency situations. The initial scope of the West Station-West Cañon project was coordinated with other entities to explore opportunities for joint participation in the project. This was done to potentially meet a wider range of system needs while minimizing the impact to the local landscape through the potential use of double circuit towers and utilization of existing transmission corridors when possible. The project was identified as an SB07-100 project in the 2015 study because it facilitates a larger resource injection from Energy Resource Zone ("ERZ") 4. Refer to the Black Hills Corporation 2020 SB07-100 Study Report included in Appendix L for more information.

The North Penrose Distribution Substation consists of constructing a new substation to accommodate two 115/13.2kV, 25MVA transformers. Currently, the community of Penrose is served radially on a 69kV line with limited contingency backup alternatives. This addition will provide the community with another source, while also offloading the 115/69kV transformers at Portland.

Pueblo area

Five projects, shown in Table 3, address reliability and contingency concerns in the Pueblo area. There has been unanticipated significant growth in the Pueblo area that will be accommodated through these future projects.

Table 3. Pueblo area projects included in the Black Hills 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
115 kV Salt Creek Substation	Q3 2021	$6.4	Not required
115 kV Desert Cove - Fountain Valley – Midway Rebuild	11/20/2021	$5.08	Not required
115kV Pueblo West Distribution Substation	1/2021	$4.5	A planned project included in the 2018 Rule 3206 filing (Proceeding No. 18M-0005E)
115kV West Station-Greenhorn Line Rebuild	9/2022	$4.5	Not required
115kV Airport Memorial – Nyberg Rebuild	9/2022	$3.7	Not required

The 115 kV Salt Creek Substation project was determined by the planning team to be a way to rectify growth concerns for the increasing demand in Colorado. Salt Creek Substation would relieve some of the load from existing distributions systems, while also supplying contingency and maintenance switching options. The addition of this substation also allows for increased capacity and contingency with distribution systems within the same area. The project is currently in land negotiation phases; therefore, the total project cost is TBD.

The 115kV Desert Cove – Fountain Valley – Midway rebuild is a result of studies that determined inadequacies in heavy summer conditions. The potential for high power flows in the north-south direction could result in a Category P2 and P4 230kV breaker failure and loss of 230kV lines. This situation would lead to inadequate thermal ratings on the 115kV Desert Cover – Fountain Valley – Midway line. To mitigate this potential issue, the 14-mile line is to be rebuilt and replaced with a minimum rating of 1110A end to end.

The 115kV Pueblo West Distribution Substation will be built to ultimately accommodate two 115/13.2kV, 25MVA transformers. This project is required to serve new industrial and agricultural load as well as contingency back-up for existing distribution infrastructure. This substation additionally addresses low voltage concerns under peak demand conditions for the area.

The 115kV West Station – Greenhorn Line rebuild is to address the age of the infrastructure. The existing 336 ACSR conductor will be replaced to increase the capacity of the line. This project will be a 12.1-mile-long rebuild that uses the current right-of-way. The project, once completed, will increase the line ratings to accommodate current summer and winter ratings.

The 115kV Airport Memorial – Nyberg rebuild is to increase the thermal capability of the lines by replacing the 336 ACSR line with 795 ACSR. Overloads on this line were identified in previous 10-year planning assessments under a contingency of losing both the Boone-Comanche 230kV and Nyberg-Baculite Mesa 115kV lines. By replacing this line, the thermal capacity can be increased to accommodate the load under the studied contingency.

Rocky Ford area

Three projects, as shown in Table 4, address reliability and contingency concerns in the Rocky Ford area.

Table 4. Rocky Ford area projects included in the Black Hills 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Boone – La Junta 115 kV Rebuild	1//2020	$15.24	Not required
South Fowler Substation	10/2021	$5.10	Not required
Boone – South Fowler 69/115kV Conversion	9/2022	$6.6	Not required

The Boone-La Junta 115 kV line rebuild is a multi-year project beginning in 2018 and ending in 2020. The entire 45-mile length of the line will be rebuilt using larger conductors to address age-related integrity issues, as well as provide additional capacity on the only transmission line serving that portion of the Black Hills system. The modest load growth forecasted for the area did not necessitate the need to implement the project at a higher operating voltage.

Previously known as “La-Junta Area Upgrades”, the South Fowler Substation and Boon-South Fowler 69/115kV conversion replaces this project. Under a study that was geared to determine the integrity of the 69kV infrastructure, it was deemed that a significant number of lines needed to be rebuilt within the near-term planning horizon. The addition of the South Fowler substation proves to be beneficial for offering additional capacity to the area, along with operational flexibility when rebuilding neighboring aged 69kV lines. The Boone-South Fowler 69/115kV conversion will be accomplished using 795 ACSR on double circuit structures to accommodate the new line, while maintaining a connection from Boone to Huerfano. This line will be a 19-mile build and is set to improve the reliability of the line regarding increased voltage.

Information concerning the specific Colorado projects included in the Black Hills 2020 10-Year Plan is contained in Appendix D. Additional general information can be found at https://www.blackhillsenergy.com/transmission-rates-and-planning/transmission-projects

B. Tri-State 10-Year Plan Overview

1. Tri-State Planning Process

Tri-State's transmission planning process is intended to facilitate the timely and coordinated development of transmission infrastructure that maintains system reliability and meets customer needs, while continuing to provide reliable, responsible, cost-based electric power to its 43 electrical cooperatives and public power districts (Member Systems). With Member Systems in four states (Colorado, Nebraska, New Mexico, and Wyoming), Tri-State is a regional power provider with only a portion of its planned transmission facilities located in Colorado and therefore included in this plan.

The primary objectives of Tri-State's transmission planning process are to meet the needs of network and point-to-point customers, maintain reliability, accommodate load growth, and coordinate interconnections. The key elements of Tri-State's transmission planning process are:

- Maintaining safe, reliable electric service to its members at the lowest possible cost;
- Improving efficiency of electric system operations;
- Providing open and non-discriminatory access to its transmission facilities; and

- Planning new transmission infrastructure in a coordinated, open, transparent and participatory manner.

Tri-State's primary planning activities center on the preparation of the 10-Year Capital Construction Plan for approval by the Tri-State Board. All projects included in Tri-State's 10-Year Capital Construction Plan adhere to NERC and WECC Standards and Criteria, FERC Order No. 890 Planning Principles, and coordinated regional planning principles, as well as the criteria outlined in Rule 3627.

Tri-State implements its transmission planning process through various studies, including:

- Reliability studies (for both bulk system infrastructure and sub-transmission);
- System impact studies;
- Transmission service requests;
- Generator interconnection studies;
- Facilities studies; and
- Economic studies.

Tri-State's Member Systems create long-range plans and other work plans that they provide periodically to Tri-State's Transmission Planning Department. When Member Systems' plans indicate the need for system upgrades or new construction, Member Systems apply to Tri-State Transmission Planning for a new or modified delivery point to be served from the Tri-State transmission system. The application contains sufficient information for Tri-State Transmission Planning to identify and consider alternatives to meet the Member Systems' requirements in a manner consistent with immediate and long-term needs in the context of the overall transmission system development.

Tri-State's contribution to the 2020 Plan was developed through an open, transparent, and participatory process that considered the needs and requirements of a wide range of stakeholders and regulatory bodies, including Tri-State's Member

Systems; transmission service customers; national and regional reliability organizations; and other transmission providers in Colorado and the region. Tri-State solicited input from a broad and diverse community of stakeholders including Member Systems, independent power producers, independent transmission companies, renewable energy advocates, environmental advocates, and federal, state, and local government agencies in the areas potentially affected by the proposed transmission projects.

The result of this coordinated and comprehensive process is a 10-Year transmission plan that includes transmission, distribution, and substation projects. Project summary information found in the following section and Appendix E focuses on the projects that involve the construction of new transmission lines in the State of Colorado. These transmission projects consist of some projects that are primarily intended to fulfill a load-serving need, some that are primarily intended to serve an identified reliability need, and some projects that are intended to provide transmission system congestion relief to better accommodate existing and future generation resources. In addition to these primary purposes, each project is a part of the bulk electric system in Colorado and therefore provides some additional benefits to the overall Colorado electric transmission system.

To understand the context and basis of Tri-State's 2020 Plan, it is important to recognize the key differences between Tri-State and other Colorado utilities. Tri-State is a generation and transmission cooperative formed and owned by its 43 member distribution cooperatives and public power systems located in four states: Colorado, Nebraska, New Mexico, and Wyoming. The territories served by Tri-State's Member Systems cover a total of approximately 200,000 square miles. This large service area results in a load density that is significantly lower than that served by urban utilities. As a cost-based cooperative, Tri-State does not operate for profit and its Board of Directors, elected by the 43 Members, sets the rates charged to Tri-State's Member Systems accordingly. Tri-State's primary mission is to provide its Member Systems reliable, affordable, and responsible wholesale electric power. Tri-State does not engage in speculative investments or other activities that are not consistent with its mission.

2. Tri-State Projects

While Tri-State's overall 2020 Transmission Plan includes transmission, substation, and distribution projects throughout Wyoming, Nebraska, Colorado, and New Mexico, this summary focuses on the larger transmission projects in Colorado. Many of these projects provide multiple benefits in terms of load serving, reliability improvements, congestion relief, or the accommodation of new generation. It should be noted that the 2020 Plan includes some projects listed in the 2018 Plan.

In January 2020, Tri-State's board of directors approved and announced that Tri-State is implementing its Responsible Energy Plan ("REP"), a transition to clean energy that will provide reliable, affordable, and responsible electricity for its Member Systems. The REP commits Tri-State and its Member Systems to significant reductions in emissions of carbon dioxide attributable to Tri-State's electricity sales to its Colorado members, including early retirement of coal-fired electric generating stations in Colorado by 2030. That commitment is combined with a commitment to a precedent-setting investment in renewable energy resources to offset the loss of conventional resources. The implementation of the REP will directly impact transmission planning.

While the full extent of new renewable energy resources are not yet known, Tri-State anticipates significant transmission infrastructure needs in eastern Colorado in support of these new resources based on the region's high potential for economic wind generation. Studies completed in the CCPG Lamar Front Range Task Force have identified several viable transmission alternatives that would support increased generation in the region by building new 345 kV infrastructure between major transmission hubs, including Lamar, Burlington, and Story switching stations.

As explained in Tri-State's Responsible Energy Plan, there is a pressing need to streamline siting and permitting processes so that transmission and generation infrastructure can be constructed in time to meet Colorado's greenhouse gas emission reduction requirements and renewable energy goals. While such streamlining will not be developed through the Commission's transmission planning rules and processes, the current siting and permitting challenges will be factors considered as Tri-State identifies the transmission system improvements needed to implement the REP's clean energy transition.

Tri-State does not yet have enough information to include in this filing transmission alternatives that may be pursued in connection with the REP. Over the next year, as resource plans are further developed with stakeholder input and eventual approval of an ERP by the Commission, Tri-State will work with stakeholders to develop transmission plans to accommodate the future resource additions and retirements. Tri-State will keep the Commission informed through future Rule 3206 and Rule 3627 filings.

Table 5. Load serving projects included in the Tri-State 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Burlington-Lamar 230 kV	2024	$58.4	Issued
Lost Canyon-Main Switch 115 kV**	TBD	$22.6	NR
Southwest Weld Expansion Project	2023	$70	Issued
Del Camino-Slater 115kV Line Uprate	2021	$1.4	NR
Sisson Project	2020	$18.8	NR
JG-Kalcevik Project	2022	$14.8	NR
Vollmer Project	2022	$7.1	NR
Lime Road Delivery Point**	TBD	$8.1	NR

*****These are conceptual projects***

Burlington-Lamar

Past studies in the Boone-Lamar area of Colorado have shown voltage collapse for the Boone-Lamar 230 kV line outage with cross-trips of all generation injected at Lamar 230 kV. In order to mitigate these violations and provide for future growth and potential new generation, Tri-State determined the best solution was to construct a new 230 kV transmission line from the existing Burlington substation to the existing Lamar substation.

Lost Canyon Main Switch 115kV

There is heavy load growth in the CO2 Loop consisting of the Yellow Jacket Switch-Main Switch-Sand Canyon-Hovenweep-Yellow Jacket 115 kV system. Constructing the new Lost Canyon-Main Switch 115 kV line will provide support to reliably meet the future load growth for the CO2 Loop in southwestern Colorado.

Southwest Weld Expansion Project

Due to large scale oil and gas development in southwest Weld County and native load growth, Tri-State is planning on constructing approximately 49 aggregate miles of 115 kV and 230 kV transmission lines to meet the forecasted demand of approximately 300 Megawatts (“MW”) within the next five years. Six potential 115 kV load-serving substations and/or line taps may be constructed by Tri-State, while new 69 kV transmission lines and substations will be constructed by United Power for the project.

Del Camino-Slater 115 kV Line Uprate

This project will replace all the remaining spans of 397.5 ACSR conductor on the Del-Camino Slater line with 477 ACSR. The increased line rating will address the limited load-serving capability of the line and allow continued area load growth.

Sisson Project

There is large oil and gas development in northwestern Colorado. This project will add approximately 20 miles of new 115 kV transmission to radially serve the new

Sisson substation radially north from the existing Keota substation. The line and substation addition will increase load-serving capability in northwestern Colorado.

JG Kalcevik Project

There is significant load growth and development north of Denver along the I-25 corridor. This project will add approximately 2 miles of 115 kV transmission to loop the existing Erie-Dacono 115kV line through the new JG Kalcevik substation. The line and substation addition will increase load-serving capability north of Denver.

Vollmer Project

There is significant load growth and development northeast of Colorado Springs. This project will tap the existing Jackson Fuller-Black Squirrel 115kV line and add approximately 2 miles of 115 kV transmission to serve the new Vollmer substation. The line and substation addition will increase load-serving capability in northeast Colorado Springs.

Lime Road Delivery Point

There is oil and gas development south of Pueblo. This project will tap the existing Stem Beach-GCC Cement Plant 115kV line and add approximately 3 miles of 115 kV transmission to serve the new Lime Road substation. The line and substation addition will increase load-serving capability in south Pueblo.

Table 6. Reliability projects included in the Tri-State 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Western Colorado Transmission Upgrade Project	2020	$57.2	Issued
Burlington-Burlington (KCEA) Rebuild	2022	$0.7	NR
Burlington-Lamar 230 kV	2024	$58.4	Issued
Falcon-Midway 115 kV Line Uprate	2022	$3.8	NR

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Falcon-Paddock-Calhan 115 kV Line**	TBD	$33.4	NR
Lost Canyon-Main Switch 115 kV**	TBD	$22.6	NR
San Luis Valley-Poncha 230kV #2	2025	$58	Req'd
Southwest Weld Expansion Project	2023	$70	Issued
Del Camino-Slater 115 kV Line Uprate	2021	$1.4	NR
JG Kalcevik Project	2022	$14.8	NR
Lamar Front Range**	TBD	TBD	Req'd

*****These are conceptual projects***

Western Colorado Transmission Upgrade Project

The 40-mile long Montrose-Nucla and Nucla-Cahone 115 kV transmission lines are old, overloaded, undersized, and must be rebuilt. To ensure continued reliability of the southwest Colorado transmission system, Tri-State is replacing them with new, higher capacity lines rated for 230 kV operation. This project will increase the load-serving capability of the southwest Colorado transmission system and also eliminate the need for the existing Nucla Remedial Action Scheme, which trips the Montrose-Nucla line when it starts to overload after contingencies/outages in the area.

Burlington-Burlington (KCEA) Rebuild

Under peak loading conditions, the K.C. Electric Association ("KCEA") 69 kV system fed from Smoky Hill substation cannot be switched to the west to pick up additional load for the loss of the Limon source after the Smoky Hill transformer is replaced with a larger unit. To mitigate this limitation, Tri-State will phase-raise the existing Burlington-Burlington KCEA line to increase the thermal rating of the line. The increased capacity will also help K.C. Electric Association serve new load in the area.

Burlington-Lamar

See description in Section III.B.2, Load Serving.

Falcon-Midway Line Uprate

The current Falcon-Midway 115 kV transmission line has a thermal rating of 95 MVA, which leads to forecasted overloads from an outage on Tri-State's 115 kV Falcon-Fuller line. In order to mitigate this problem, Tri-State is raising, moving, or rebuilding structures along the line to increase the overall line rating to 145 MVA. The increased capacity will help serve Mountain View Electric Association's ("MVEA") customer load in the area.

Falcon-Paddock-Calhan 115 kV Line

The current Falcon-Paddock-Calhan 69 kV transmission line will be rebuilt to create a 115 kV loop in MVEA's central system. The 115 kV line will improve system reliability by looping the existing radial 115 kV and 69 kV substations in MVEA's system and provide increased voltage support. The 115 kV line also will help serve MVEA's customer load growth in the area.

Lost Canyon Main Switch

See description in Section III.B.2, Load Serving.

San Luis Valley-Poncha 230 kV #2

New high-voltage transmission must be built in the San Luis Valley ("SLV") region of south-central Colorado to maintain electric system reliability and customer load-serving capability, and to accommodate development of potential generation resources. Tri-State and Public Service, working through CCPG, facilitated a study of the transmission system immediately in and around the SLV and developed system alternatives that would improve the transmission system between the SLV and Poncha Springs, Colorado. Both Tri-State and Public Service have electric customer loads in the SLV region that are served radially from transmission that originates at or near Poncha. The study concluded that, at a minimum, an additional 230 kV line is needed to increase system reliability. Studies show that this could be accomplished by either adding a new 230 kV line or rebuilding an existing lower voltage line and operating it at 230 kV.

Southwest Weld Expansion Project

See description in Section III.B.2, Load Serving.

Del Camino-Slater 115 kV Line Uprate

See description in Section III.B.2, Load Serving.

JG Kalcevik Project

See description in Section III.B.2, Load Serving.

Lamar Front Range

The Lamar Front Range Project was developed jointly through the CCPG to significantly improve load-serving capability, reliability, and potential resource accommodation in eastern and southeastern Colorado. The project could provide connectivity to the bulk transmission systems of Tri-State and PSCo, and provide strong "looped service" to areas with long radial transmission configurations. In concept, the project could create a transmission system capable of at least 2000 MW of new generation in eastern and southeastern Colorado. As the actual transmission needs in the original Lamar Front Range Project area have been smaller over the last few years, several projects have been implemented at a smaller scale, but in a manner consistent with the outline of the original Lamar Front Range Project.

This conceptual project is currently being re-evaluated in the Lamar Front Range Task Force under CCPG. The project identifies transmission element additions that are needed to meet both companies' needs, including delivery of future generation to loads in the Denver and Front Range areas. The conceptual Lamar Front Range project under study envisions 345 kV transmission lines connecting Lamar to the Pueblo area, Lamar to the Burlington area, and the Burlington area to the Missile Site, Story and Pawnee areas.

Table 7. Generation Congestion projects in the Tri-State 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Burlington-Lamar 230 kV	2024	$58.4	Issued
Lamar Front Range**	TBD	TBD	Req'd
Lamar-Vilas 230 kV**	TBD	$90	Req'd

*****These are conceptual projects***

Burlington-Lamar

See description in Section III.B.2, Load Serving.

Lamar Front Range

See description in Section III.B.2, Reliability.

Lamar-Vilas 230 kV Transmission

See description in Section III.C.2, Public Service Conceptual Plans.

Information concerning the specific Colorado projects included in the Tri-State 2020 10-Year plan is contained in Appendix E. Additional information and supporting documentation can be found at:
http://www.tristate.coop/transmission-planning

C. Public Service 10-Year Plan Overview

Public Service is one of four electric utility operating companies of Xcel Energy Inc., which is an investor-owned utility serving approximately 1.5 million electric customers in the State of Colorado. Public Service serves approximately 75 percent of the state's population. Its electric system is summer-peaking with a 2019 peak customer demand of 6881 MW. The entire Public Service transmission network is located within the State of Colorado and consists of over 4,700 miles of transmission lines. Colorado is on the eastern edge of the WECC transmission system, which constitutes the Western Interconnection. The Western Interconnection operates asynchronously from the Eastern Interconnection. The Public Service transmission system is interconnected with the transmission system of its affiliate, Southwestern Public Service Company, via a jointly owned tie line with a 210 MW High Voltage Direct Current ("HVDC") back-to-back converter station. Most of the Public Service retail service customers are located in the Denver-Boulder metro area. However, the Public Service retail service territory also includes the I-70 corridor to Grand Junction, the San Luis Valley region, and the cities and towns of Greeley, Sterling, and Brush. The Company's largest retail electric customer is EVRAZ North America, an industrial steel mill, located in Pueblo.

1. Public Service Planning Process

The goal of coordinated planning, as described in Commission Rule 3627 and historically practiced by Public Service and other TPs, is to develop the best possible transmission plan to meet present and future demands for electricity, taking into account a number of diverse factors. At its most basic level, transmission planning strives to meet customers' energy needs in a reliable and cost-effective manner.

The Public Service transmission planning process is intended to achieve the following objectives:

- Maintain reliable electric service;
- Improve the efficiency of electric system operations, including the provision of open and non-discriminatory access to our transmission facilities pursuant to FERC requirements;
- Identify and promote new investments in transmission infrastructure in a coordinated, open, transparent, and participatory manner; and

- Involve stakeholders during the transmission planning process and review of alternatives.

There are multiple drivers to the planning process, including customer load growth, accommodation of new resources, retirement of existing resources, compliance with state and federal rules and standards, replacement of aging infrastructure, and public policy initiatives. The planning process is coordinated with all the other transmission providers in the state to avoid duplication and reduce costs to the end use customer.

As described in earlier sections, coordinated transmission planning in the State of Colorado depends on careful consideration of numerous factors and variables, as well as thoughtful consideration of input from organizations and individuals on the regional, sub-regional, and local level.

One of the strategic priorities for Public Service is to be a leader in transitioning its generation toward cleaner energy. The goal is to serve customers with cleaner, reliable energy through increased ownership of wind and solar generation, invest in the grid, including advanced technologies and transmission that enable more renewable energy, and reduce carbon and other emissions. This strategy has impacted transmission planning over the last two years and will continue to impact planning into the future.

In September 2018, the Commission approved the 2017 Company's Preferred Colorado Energy Plan Portfolio (CEPP), which stemmed from the PSCo 2016 Electric Resource Plan. As a result of the CEPP, PSCo will be retiring 660 MW of coal-fired generation at Comanche, and adding almost 1000 MW of new wind generation and over 700 MW of new solar generation to its system. In 2019, Xcel Energy released its Corporate Responsibility Report, also referred to as Destination 2050, which describes the Company's vision for a carbon-free future by 2050.

Destination 2050 lays out an interim goal to reduce carbon emissions produced from the electricity that serves our customers by 80 percent from 2005 levels by 2030.

The 2017 CEPP, the Clean Energy Plan (to be filed by Public Service in its next Electric Resource Planning process) and Destination 2050 have had significant impacts to the Public Service transmission planning processes as will be described in later sections of this report.

2. Public Service Projects

Table 8, below, lists the Public Service projects. Note that some costs may have changed from previous filings with the PUC, due to changes in costs for issues such as materials, permitting, construction, and administration.

Table 8. Public Service 10-Year Plan

Project Name	ISD	Cost (millions)	CPCN
Completed			
Missile Site - Shortgrass 345 kV Transmission	2018	$104.9	G
Two Basins Relocation	2018	$24.1	NR
Bluestone Valley Substation Phase 1	2019	$12.0	NR
Moon Gulch 230 kV Substation	2018	$1.7	G
Thornton Substation	2019	$21.4	G
Pawnee-Daniels Park 345 kV Transmission	2019	$169.4	G
New to 2020 Filing			
Shortgrass Switching Station	2020	$20.6	G
CEPP Voltage Support	2020	$93.6	R
Greenwood – Denver Terminal 230kV line	2022	$50.3	R
CEPP Switching Station Bid X645	2022	$20.0	R
CEPP Switching Station Bid S085	2022	$12.0	R
Shortgrass – Cheyenne Ridge 345 kV Transmission	2020	$62.3	G
Previously Listed Projects			
NREL Substation	2020	$10.4	NR
Avery Substation	2021	$10.3	G
Ault-Cloverly 230/115 kV Transmission	2022	$66.7	G

Project Name	ISD	Cost (millions)	CPCN
Avon-Gilman 115 kV Transmission	2022	$11.4	NR
CSU Flow Mitigation	2022	TBD	R
Mirasol (formerly Badger Hills) Switching Station (CEPP Bid X647)	2022	$12.0	R
Conceptual			
Weld-Rosedale-Box Elder – Ennis 230/115kV	TBD	TBD	R
Weld County Expansion Transmission	TBD	TBD	R
Bluestone Valley Substation Phase 2	TBD	TBD	NR
Glenwood-Rifle 115 kV Transmission	TBD	TBD	U
Hayden-Foidel-Gore 230 kV	TBD	TBD	U
Lamar-Front Range Transmission	TBD	TBD	R
Lamar-Vilas 230 kV Transmission	TBD	TBD	R
Parachute-Cameo 230 kV #2 Transmission	TBD	TBD	R
Rifle-Story Gulch 230 kV Transmission	TBD	TBD	R
Wheeler-Wolf Ranch 230 kV Transmission	TBD	TBD	NR
San Luis Valley – Poncha 230 kV[3]	TBD	TBD	R
Poncha – Front Range 230 kV	TBD	TBD	R
Distribution Driven Projects			
Barker Distribution Substation	2021	$29.8	NR
Wilson Distribution Substation	TBD	$4.0	NR
Titan Distribution Substation	2022	$13.0	G
Dove Valley Distribution Substation	2023	TBD	NR
High Point Distribution Substation	2022	$9.0	R
Stock Show Distribution Substation	2026	TBD	NR
New Castle Distribution Substation	TBD	TBD	NR
Solterra Distribution Substation	TBD	TBD	U
Superior Distribution Substation	TBD	TBD	U
Sandy Creek Distribution Substation	TBD	TBD	U

[3] Tri-State lists as “planned” with 2025 ISD.

Key: R – Required, NR – Not Required, G – Granted, U - Uncertain

Public Service’s transmission plan does not currently include multi-state transmission projects. However, Public Service watches for such opportunities. While some of the elements of the current transmission plan could be used as components of a regional transmission project, Public Service has not identified regional project opportunities at this time to include in this plan.

Following is a brief, narrative description of each Public Service project included in Table 1 and how it fits into the overall 2020 Plan. Information for the auxiliary projects shown in Table 8, as well as maps of the Public Service projects for each of the time-frames listed below can be found in Appendix F. Projects are arranged by their anticipated in-service dates.

Planned Projects

Public Service's planned transmission projects can generally be placed in two basic categories. The first category consists of projects that are needed primarily for load growth or reliability purposes. These include both new projects as well as rebuilds or upgrades to existing transmission lines. Native load peak demand in Public Service's service territory has remained fairly flat during the past five years. The expiration of wholesale contracts and the participation of wholesale customers in the Comanche 3 power plant have contributed to this flat load growth. Since 2009, the Public Service firm wholesale load has decreased, but the loss of wholesale load was offset by load growth within the retail sector. The level of load growth also is due to increases in energy efficiency and demand-side management programs, changes in appliance efficiency, and the increase in use of on-site photovoltaic energy systems. Public Service presently projects the native load to grow by about 0.7% from 2019 to 2026.

The second category consists of projects that are planned primarily to accommodate new generation resources. For Public Service, these projects tend to be associated with its electric resource plans, such as the 2017 CEPP. Senate Bill 07-100 also plays a role in the development of those plans, since it is intended to promote proactive planning to accommodate beneficial resources. These projects tend to include large transmission projects to access specific areas of the state that have the potential to host future generation facilities. Through the SB07-100 process, Public Service has developed plans to access each ERZ in Colorado. Some of these plans may be used or modified to accommodate the future Clean Energy Plan and Destination 2050 goals.

Projects Implemented Since 2018

This section describes the Public Service projects that have been placed in-service since the 2018 Rule 3627 10-Year Transmission Plan ("2018 Filing"). The following project(s) consisted of upgrades or additions to existing substations.

Missile Site - Shortgrass 345 kV Transmission

This project was described in the 2018 filing as the Rush Creek – Missile Site 345 kV Transmission Project, or Rush Creek Gen-tie. The project includes the 600 MW Rush Creek wind generation project and an approximately 82-mile 345 kV transmission line that has been built in parts of Arapahoe, Elbert, and Lincoln counties. Since the transmission line is a radial line that accommodates new generation, it is sometimes referred to as a "gen-tie". The Rush Creek wind project includes two collector stations. One collector is located at the new Pronghorn Switching Station, located approximately 42 miles from Missile Site Substation. The second collector is located at the new Shortgrass Switching Station, which is located at the eastern end of the gen-tie, approximately 40 miles from Pronghorn Switching Station.

Construction started on the transmission line in August 2017 and it was placed in service in July 2018 with an approximate cost of $104.9 million.

As part of the Settlement Agreement for the Rush Creek Wind Project proceedings, Public Service took a leadership role in the Rush Creek Task Force created within the CCPG. The task force analyzed the costs and benefits of 19 alternative proposals to potentially integrate the gen-tie as a network facility. The process provided a forum for stakeholder participation and comment.

Two Basins Relocation Project

This project consisted of relocating three existing 115 kV transmission lines that connect to the North Substation. The project was necessary to accommodate the City and

County of Denver ("CCOD") Two Basins Storm Water Drainage Project, which provides 100-year storm protection for certain areas of the city. The project also was required to accommodate the Colorado Department of Transportation ("CDOT") I-70 Expansion Project. The project involved: 1) Re-locating a portion of the existing North-Capitol Hill 115 kV underground line. 2) Re-locating the entire existing North-California 2.25-mile 115 kV underground line and replacing it with new conductor, and 3) Re-locating and replacing four overhead structures on the existing North-Sandown 115 kV line. The CPUC determined that the project was in the ordinary course of business and did not require a Certificate of Public Convenience and Necessity ("CPCN"). The project was placed in-service in 2018 and a cost of $24.1 million.

Bluestone Valley Substation (Phase 1)

The 2018 filing listed Bluestone Valley Substation as a new substation project to improve reliability and provide additional load interconnections for customers in the area. The original scope of this project consisted of a new Bluestone Valley 230/69 kV Substation. The substation would include a 230/69 kV transformer and would interconnect the existing Parachute-Cameo 230 kV line and the existing DeBeque-Cameo 69 kV line. From Bluestone Valley Substation, a new line would be constructed to a new Grand Valley Power Clear Creek Substation. Public Service split this project into two phases: A 69 kV phase ("Phase 1") and a 230 kV phase ("Phase 2"). To expedite reliability improvements to the lower voltage network, Public Service has completed Phase 1. Phase 2 is still considered conceptual and may be constructed at a later time based on local load growth. Phase 1 included construction of a new Bluestone Valley 69 kV Switching Station that connects to the existing DeBeque-Cameo 69 kV line. The project resulted in a DeBeque-Bluestone Valley-Cameo 69 kV line. Phase 1 of this project was placed in-service 2019, at a cost of $12.0 million.

Moon Gulch Substation

Moon Gulch Substation is a new distribution substation built in the City of Arvada within Jefferson County. The substation taps the existing Plains End-Simms 230 kV line. The substation was built to serve load growth in the Arvada area and also to provide backup service to the existing Eldorado and Ralston distribution substations. The project was placed in-service in 2018 at a cost of $1.7 million.

Thornton Substation

This project consisted of constructing a new substation in Thornton to serve the increase in customer distribution load in that area. This new substation serves the City of Thornton in the north metro Denver area and provides back-up support to the existing Glenn and Washington distribution substations. The project was placed in-service in 2019, at a transmission cost of $21.4 million.

Pawnee-Daniels Park Transmission

The Pawnee-Daniels Park 345 kV Transmission Project consists of a new 125-mile 345 kV transmission line from the Pawnee Substation in northeastern Colorado to the Daniels Park Substation, south of the Denver-Metro area. The project also resulted in the construction of a new Harvest Mile 345 kV Substation, near Smoky Hill Substation, and a new Harvest Mile-Daniels Park 345 kV line. The project also interconnects with the Missile Site 345 kV Substation. This project was planned in accordance with Senate Bill 07-100, in that it accommodates generation in designated ERZs 1 and 2. The Pawnee-Daniels Park Project was placed in-service in December 2019, at a cost of $169.4 million.

Planned Transmission and Substation Projects (Not Previously Listed)

This section describes the Public Service projects that have not been included in previous Rule 3627 filings.

Planned Projects Related to the 2017 Colorado Energy Plan Portfolio

Shortgrass – Cheyenne Ridge 345 kV Transmission Line Project and Shortgrass Switching Station

The Shortgrass – Cheyenne Ridge 345 kV Transmission Line Project consists of an approximately 73-mile, 345 kV transmission line which will extend from the Shortgrass Switching Station to the Cheyenne Ridge wind farm collector stations. The Shortgrass Switching Station not only provides an interconnection for part of the Rush Creek wind generation, but also will interconnect the 300 MW Bronco Plains wind project and the Cheyenne Ridge 500 MW wind project that are included in the Company's CEPP. The project is located in Lincoln, Kit Carson and Cheyenne counties. The project was granted a CPCN, is estimated to cost approximately $52.7 million, and is scheduled to go in service in 2020.

Greenwood -Denver Terminal 230 kV Transmission Project

The Greenwood – Denver Terminal Project consists of an approximately 15 miles of new 230 kV transmission line between the Company's existing Greenwood and Denver Terminal substations. The line is needed to accommodate the 2017 CEPP. The new line will be implemented by rebuilding existing transmission facilities from the Greenwood Substation to the Denver Terminal Substation within existing right-of-way (ROW). The existing Greenwood, Arapahoe, and Denver Terminal substations all will require modifications to accommodate the project. The project is located in six different city boundaries: Centennial, Greenwood Village, Littleton, Englewood, Sheridan and Denver. The Project is estimated to cost approximately $50.3 million and it is planned to be in service by December 31, 2022. The Company plans to file a CPCN for this project early in 2020.

CEPP Voltage Control Facilities

A series of network voltage control devices need to be installed on the Public Service transmission system to accommodate the CEPP generation. The Company is proposing the facilities described in the table below.

Table 9. CEPP Voltage Control Facilities

Substation / Switchyard Location	Implementation Devices to be installed	Estimated In-Service Date	Estimated Cost (millions)
CF&I Furnace	± 95 MVAR STATCOM	Dec. 2023	$32.0
	One (1) dynamic voltage support device		
	85 MVAR of shunt capacitance		
	One (1) 85 MVAR capacitor		
Daniels Park	120 MVAR of shunt capacitance	Dec. 2020	$3.6
	One (1) 120 MVAR capacitor		
Harvest Mile	240 MVAR of shunt capacitance	June 2020	$5.4
	Two (2) 120 MVAR capacitors		
Missile Site	360 MVAR of shunt capacitance	June 2020	$9.5
	Three (3) 120 MVAR capacitors		
	Rush Creek Master Voltage Controller AVSO	Dec. 2020	$5.2
Pronghorn	± 150 MVAR STATCOM	Dec. 2020	$31.7
	One (1) dynamic voltage support device		
Shortgrass	60 MVAR of shunt reactance	April 2020	$6.2
	Two (2) 30 MVAR reactors		
Total			**$93.6**

The cost of the combined facilities is estimated to be approximately $93.6 million and they will be placed in service between 2020 and 2023. A CPCN was filed for this project in December 2019.

CEPP Generation Interconnection Facilities

In addition to the Shortgrass Pronghorn, and Mirasol (formerly Badger Hills – discussed in the Planned Transmission Projects from Previous Filings below) switching stations, other interconnection facilities must be constructed to accommodate the CEPP generation. At this time, the facilities include expanding two existing substations and constructing two new switching stations. The new switching stations include one that will connect to the Hartsel – Tarryall 230 kV line, and one that will connect to one Comanche – Daniels Park 345 kV line. The two existing substation that are proposed to be modified are the Boone and Midway 115 kV substations. The Company intends to file a CPCN for these facilities in 2020.

Planned Transmission Projects (Listed in Previous Rule 3627 Filings)

NREL Switching Station

This project consists of a new switching station that taps the existing Plainview-Eldorado 115 kV line south of Boulder. The U.S. Department of Energy's National Renewable Energy Laboratory ("NREL") operates a hybrid generation facility at its National Wind Technology Center, located approximately 1 mile east of the line. This facility is currently interconnected via distribution service, so the generation capacity is limited. This project is needed to interconnect the generation to the transmission system and allow for additional generation interconnections. The project does not require a CPCN, has a planned in-service date of 2020, with an estimated cost of $10.4 million.

CSU Flow Mitigation Project

This project was described in the 2018 filing as the addition of a phase shifting transformer ("PST") to the Monument Substation on the Monument-Flying Horse 115 kV transmission line, to control power flows through the Colorado Springs Utilities ("CSU") transmission system. Studies have shown that when there are heavy power transfers on the transmission system between Pueblo and the Denver, there is a potential for unacceptable loading to occur on the CSU transmission system. As a temporary mitigation measure, Public Service has implemented an operating procedure that opens up a 115 kV line on the north end of the system where the CSU and Public Service systems connect. The issue has been studied through the Douglas Elbert and El Paso (DEEP) Subcommittee of the CCPG. Upon completion of additional studies, the DEEP Subcommittee developed an alternative solution that consisted of a series reactor rather than a phase shifting transformer. The series reactor alternative accomplishes the same goal, but with advantages to the phase shifting transformer. The series reactor project had an estimated cost of $9.9 million and a potential in-service date of 2022. Recently, CSU has been evaluating additional alternatives. Public Service is continuing to work with CSU, TSGT, and the DEEP Subcommittee to determine a final long-term transmission solution to mitigate the potential overloads. The project will likely require a CPCN.

Mirasol Switching Station

This project was described in the 2018 filing as a Badger Hills 345/230 kV substation. The project is presently planned as a 230 kV switching station. This project is one of several interconnecting switching stations that will be needed to accommodate generation associated with the Public Service 2017 CEPP. The Mirasol Switching Station will be located approximately 12 miles southeast of Comanche Substation, and will interconnect one of the Comanche - Midway 230 kV lines. The project is being designed to have the flexibility to allow for additional generation interconnections, as well as existing and future transmission lines. The project has a planned in-service date of 2022, with an estimated cost of $12 million. The Company intends to include this project with the other interconnection switching stations when it files a CPCN for these facilities in 2020.

Ault-Cloverly 230/115 kV Transmission Project

The Ault-Cloverly Project consists of approximately 25 miles of new 230 kV and 115 kV transmission lines originating at the existing Western Area Power Administration ("WAPA") Ault Substation near the town of Ault, and terminating at the Public Service Cloverly Substation on the northeast edge of Greeley. The transmission also will interconnect with two new PSCo substations: Husky Substation, which will replace and is planned to be built near the existing PSCo Ault 44 kV Substation, and Graham Creek Substation, which will replace and is planned to be built near the existing PSCo Eaton 44 kV Substation. One objective of the project is to improve reliability by replacing the existing 44 kV system in the area with higher voltage transmission facilities. However, the project also will increase the load-serving and generation resource capability in the area.

The project was granted a CPCN and has a planned in-service date of 2022 with an estimated cost of $66.7 million.

Avon-Gilman 115 kV Transmission Project

The Avon-Gilman 115 kV Transmission Project consists of constructing a new 10-mile 115 kV line in Eagle County for reliability and to provide an alternate transmission source to Holy Cross Energy customers. The project does not require a CPCN, has a planned in-service date of 2022, and has an estimated cost of $11.4 million.

3. Public Service Conceptual Plans

Conceptual Plans

The following transmission plans are considered conceptual in that they have no specific in-service date. Implementation of these plans is primarily affected by load forecasts and electric resource needs. Once a need is established, in-service dates can depend on many factors, including but not limited to regulatory proceedings, siting and land permitting, coordination of construction outages, and material delivery times. Public Service continues to assess the system conditions that may drive implementation for these plans.

Conceptual Plans Related to Load Growth

Bluestone Valley Substation (Phase 2)

As mentioned previously, this project has been divided into two phases. Phase 2 of the project would consist of expanding the substation to include 230 kV facilities, which would include a 230/69 kV transformer and interconnect the Rifle-Cameo 230 kV line. Implementation of Phase 2 will depend on the local load growth.

Glenwood-Rifle Transmission

This plan has been described in previous filings, and consists of upgrading the Glenwood Springs-Mitchell Creek-New Castle-Silt Tap line from 69 kV to 115 kV and new construction to reroute the Silt-Rifle line to the Rifle Substation at 115 kV. A portion of the rerouted 115 kV line will be double-circuited with the Rifle-Hopkins 230 kV line. Costs for the plan have not been estimated, and moving forward with the plan will depend on load growth around Glenwood Springs.

Hayden-Foidel Creek-Gore Pass 230 kV Transmission

This plan has been described in previous filings and would consist of tying the Hayden-Gore Pass 230 kV line into the Foidel Creek Substation to increase reliability in the region. Reliability concerns are being mitigated by adding reactors at the Wolcott 230 kV bus, so there are no plans to move forward with this project at this time.

Parachute-Cameo 230 kV #2 Transmission

This project has been described in previous filings and is an extension of the Rifle-Parachute 230 kV line. It would consist of a new, approximately 30-mile 230 kV transmission line that would connect the existing Parachute and Cameo substations on the western slope of Colorado. Its primary purpose would be to increase reliability and to serve load growth in the region. Preliminary analysis estimated the cost to be approximately $48 million, but actual costs, and implementation of the project will depend on load growth in the area.

Rifle-Story Gulch Transmission

The project has been described in previous filings and would consist of a new radial 230 kV transmission line that would be used to serve customer loads in Garfield County. The line would be approximately 25 miles long and run between the existing Rifle (Ute) Substation to a new Story Gulch Substation. Preliminary analysis estimated the project cost to be approximately $24 million, but actual costs and implementation will depend on load growth in the area.

Wheeler-Wolf Ranch

The project has been described in previous filings and would consist of a new radial 230 kV transmission line that would be used to serve customer loads in Garfield County. The line would be approximately 18 miles long and run between the existing Wheeler

Substation to a new Wolf Ranch Substation. The line also would interconnect to the Middle Fork Substation. Preliminary analysis estimated the project to cost approximately $17 million, but actual costs and implementation will depend on load growth in the area.

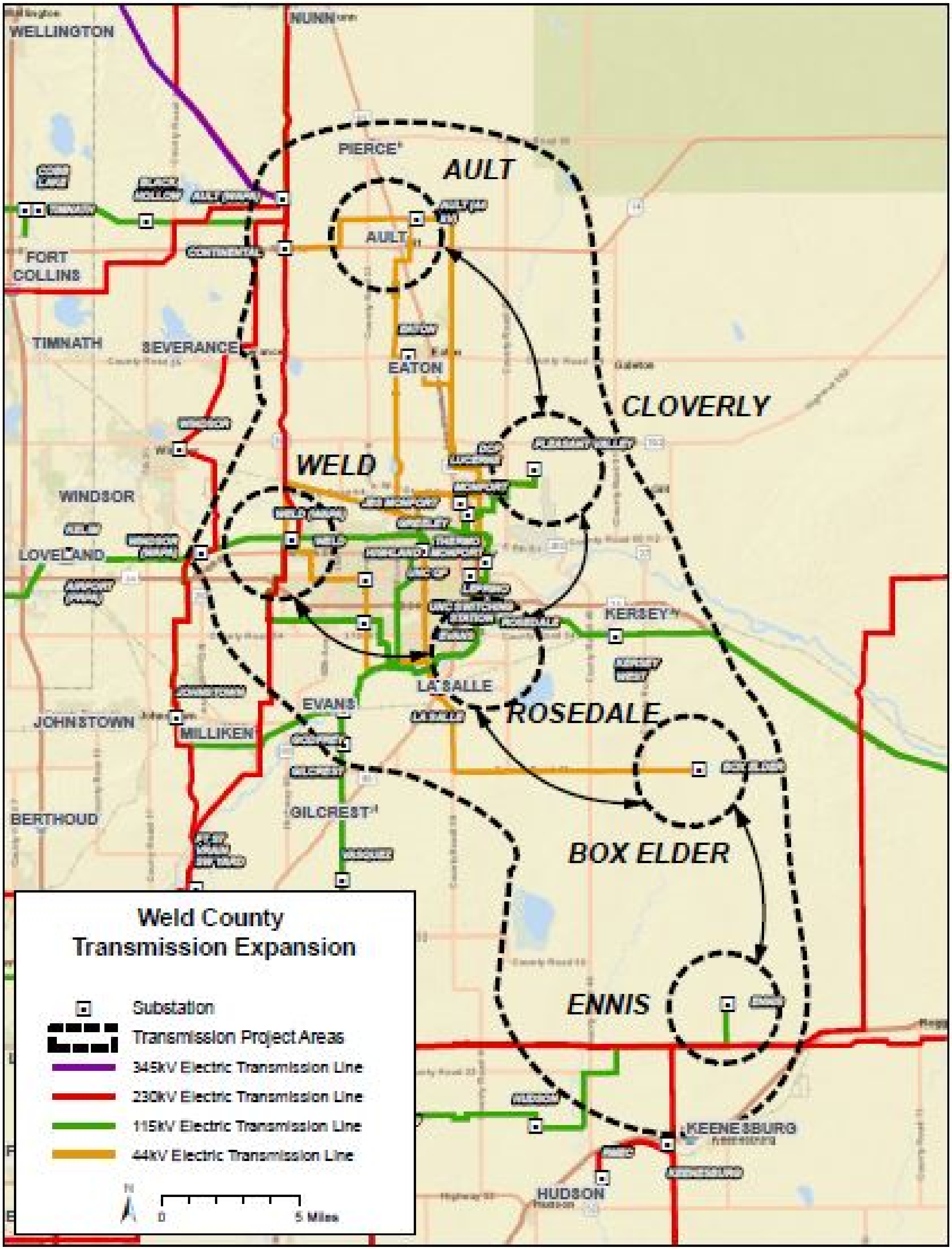
Conceptual Plans Related to SB07-100 / Clean Energy Plan Goals

Weld-Rosedale-Box Elder - Ennis 230 & 115 kV Transmission Lines

This project was referred to in the 2018 filing as the Weld – Rosedale – Milton 230 kV project. However, Public Service has been evaluating alternatives that would terminate at locations other than Milton within its service territory. As mentioned in the 2018 filing, Public Service has been working through the CCPG Northeast Colorado ("NECO") Subcommittee to develop a transmission plan for the area south of Greeley. The objective is to continue the replacement of the existing 44 kV system in the area, increase the ability to accommodate future load growth, and allow for beneficial resource development. The plan also should align with other transmission projects and plans in the area, including the Ault-Cloverly Project and the Southwest Weld Expansion Project ("SWEP"). A 230 kV line from Weld to Rosedale and a 230 kV or 115 kV line from Rosedale to Box Elder to Ennis would meet the objectives. However, until the NECO studies are completed and an actual project is recommended, the projects are listed as conceptual with no specified in-service date or estimated costs.

Weld County Transmission Expansion

This plan was described in the 2018 filing as a means to allow interconnection of new resources and complement other transmission plans in Northeast Colorado such as the Ault-Cloverly 230/115kV Project and the Weld-Rosedale-Box Elder-Ennis 230 and 115kV Transmission Project. The Weld County Expansion continues to be a general planning placeholder that captures the planning efforts for Northeast Colorado, including the Greeley area. This project may be considered as a third or eastern phase of the planning efforts in the area that have been taking place in the CCPG NECO Subcommittee. The Weld County Expansion could be a combination of planned and conceptual projects, such as the Ault-Cloverly Project, and the Weld-Rosedale-Box Elder - Ennis 230 & 115 kV lines, or, the Weld County Expansion could be a new project. Regardless, the Weld County Expansion may be a project that could enable Public Service to meet its Clean Energy Plan goals.


WELLINGTON
NUNN
PIERCE
AULT
FORT COLLINS
TIMNATH
SEVERANCE
EATON
CLOVERLY
WELD
WINDSOR
LOVELAND
KERSEY
LA SALLE
ROSEDALE
EVANS
JOHNSTOWN
MILLIKEN
GILCREST
BERTHOUD
BOX ELDER
ENNIS
KEENESBURG
HUDSON
Weld County
Transmission Expansion
Substation
Transmission Project Areas
345kV Electric Transmission Line
230kV Electric Transmission Line
115kV Electric Transmission Line
44kV Electric Transmission Line
0
5 Miles

Lamar-Front Range Transmission

The Lamar-Front Range plan originally was planned as a means to deliver an estimated 2000 MW of new generation from energy resources near Lamar and Burlington to load centers along the Front Range. The plan was conceived as a joint project between Public Service and Tri-State. A primary driver for Public Service was to meet an SB07-100 objective to plan transmission from the ERZ-3. The original plan included the following transmission components:

- Two 345 kV transmission circuits between Lamar and Avondale
- Two 345 kV transmission circuits between Lamar and Burlington
- Two 345 kV transmission circuits between Burlington and Big Sandy
- One 345 kV transmission line between Big Sandy and Missile Site
- One 345 kV transmission line between Big Sandy and Story
- One 345 kV transmission line between Story and Pawnee
- A new Avondale Substation
- Two 230 kV transmission circuits between Lamar and Vilas

The original Lamar-Front Range project was estimated to cost approximately $900 million. However, since the project is being re-evaluated, revised cost estimates have not been determined.

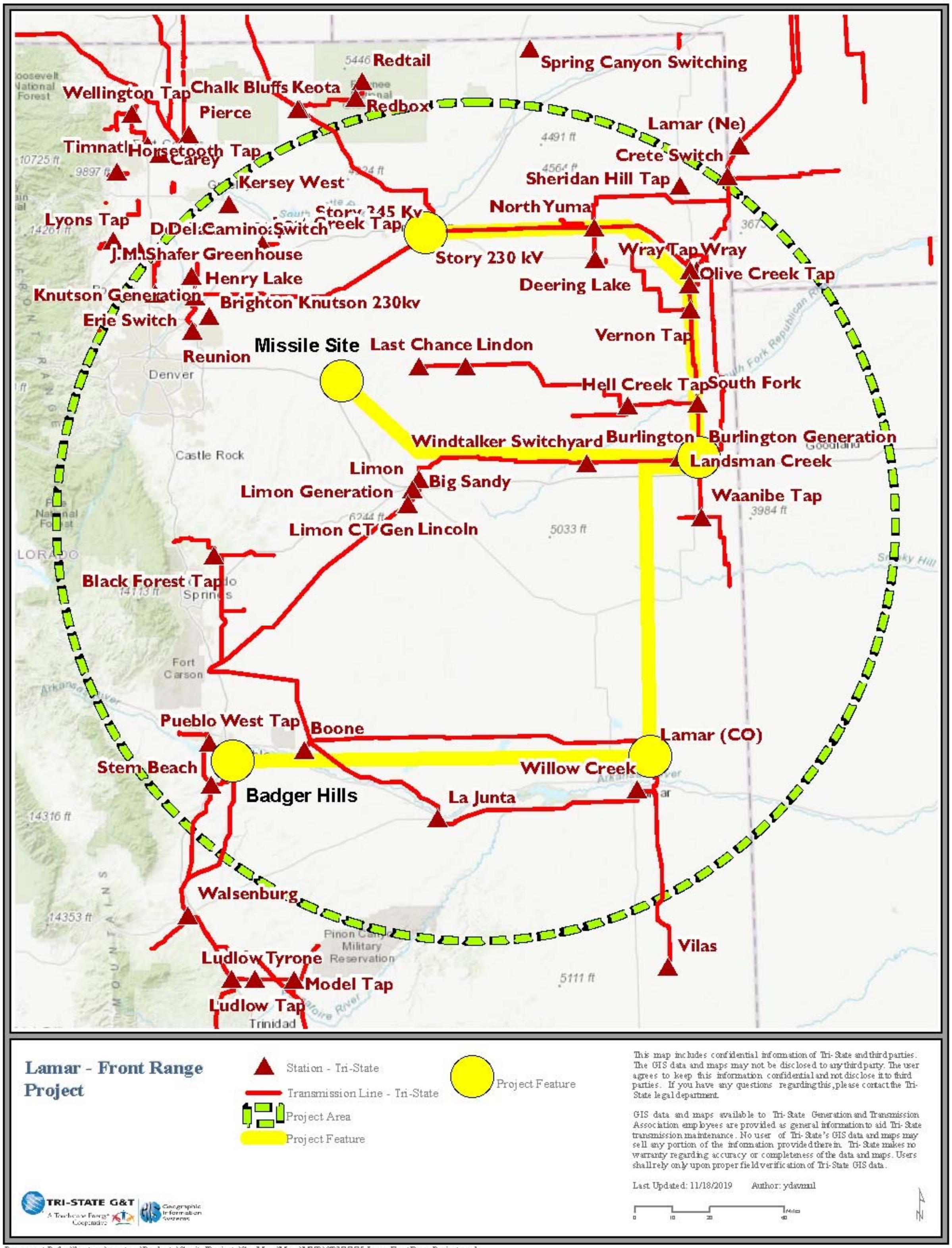
Since the plan was developed, a number of significant projects that could either be considered segments of, or are consistent with the design of the plan have been implemented or planned. These include:

- Construction of the Missile Site – Pronghorn – Shortgrass 345 kV line
- Construction of the Burlington – Wray 230 kV line
- Plans for the Shortgrass – Cheyenne Ridge 345 kV line
- Plans for a Burlington – Lamar 230 kV line

As a result, in 2019, the CCPG Lamar-Front Range Task Force (LFRTF) was formed to revisit the Lamar-Front Range Transmission Project. The objective of the task force is to evaluate transmission alternatives in eastern and southeast Colorado that will facilitate the delivery of new renewable and other low-cost generation to load centers, improve transmission system reliability, and increase the operational flexibility of both transmission and generation assets.

The LFRTF evaluated numerous transmission alternatives. No preferred alternative has been identified, but some alternatives and combinations of alternatives show technical merit and meet the overall objective. For example, a potential plan that may be able to advance Public Service's future Clean Energy Plan objectives might include the following components:

- Networking the Missile Site – Cheyenne Ridge 345 kV line to Burlington
- New 345 kV transmission from Burlington – Lamar – Comanche
- New 345 kV transmission from Burlington – Missile Site
- New 345 kV transmission from Burlington - Pawnee



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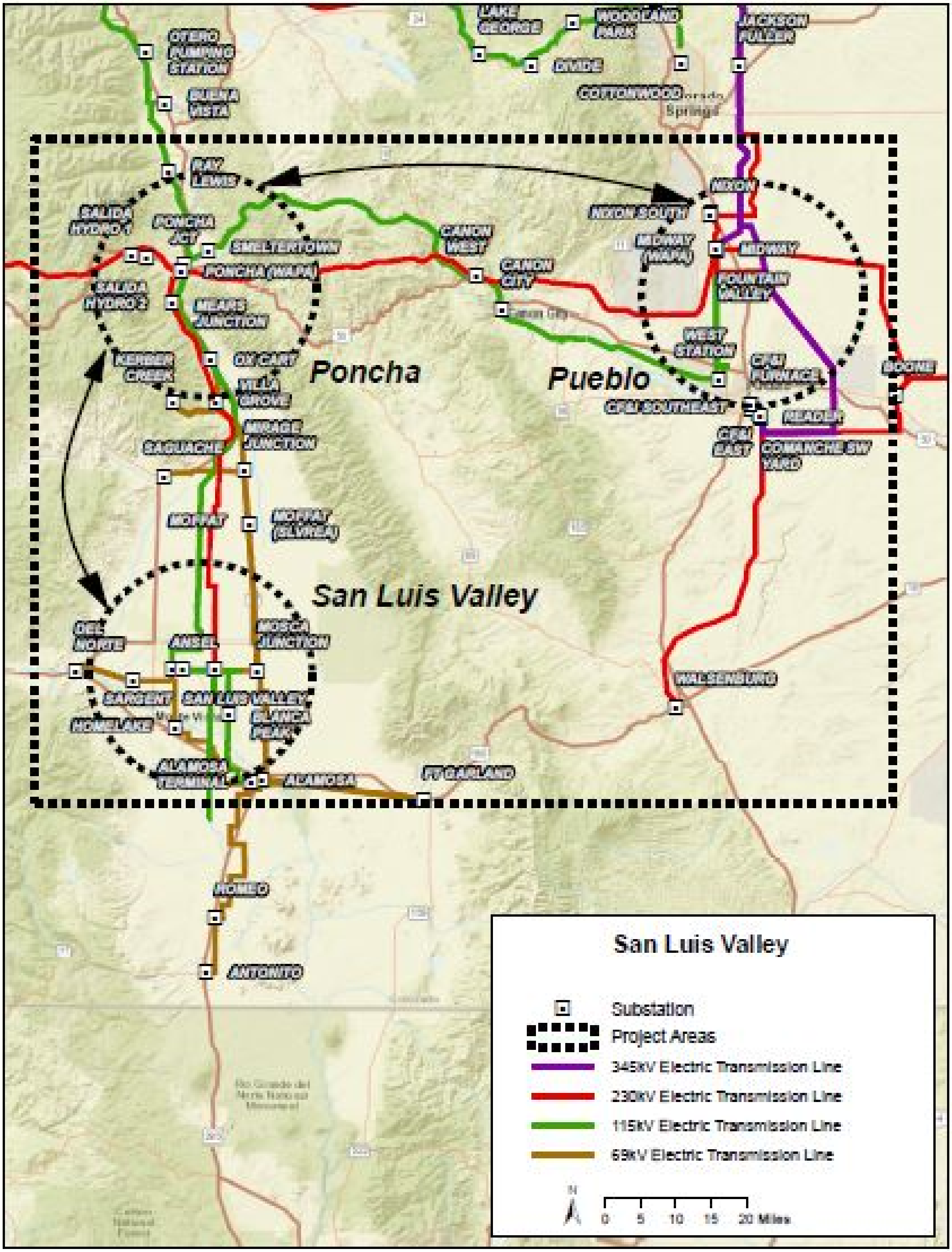
San Luis Valley

Similar to Tri-State, Public Service also recognizes that new high-voltage transmission in the San Luis Valley would improve electric system reliability and customer load-serving capability, and accommodate development of potential generation resources. Studies indicated that a new 230 kV transmission line from the San Luis Valley Substation to Poncha Substation would be a first step to accomplish the reliability objectives. Transmission beyond Poncha to the Front Range would enhance reliability and provide additional generation export out of the San Luis Valley and help meet the Public Service Clean Energy Plan goals.


LAKE GEORGE
WOODLAND PARK
JACKSON FULLER
OTERO PUMPING STATION
DIVIDE
COTTONWOOD
BUENA VISTA
RAY LEWIS
NIXON
NIXON SOUTH
SALIDA HYDRO 1
PONCHA JCT
SMELTERTOWN
CANON WEST
MIDWAY (WAPA)
MIDWAY
PONCHA (WAPA)
CANON CITY
SALIDA HYDRO 2
MEARS JUNCTION
FOUNTAIN VALLEY
WEST STATION
KERBER CREEK
OX CART
Poncha
Pueblo
CF&I FURNACE
BOONE
VILLA GROVE
CF&I SOUTHEAST
READER
MIRAGE JUNCTION
SAGUACHE
CF&I EAST
COMANCHE SW YARD
MOFFAT
MOFFAT (SLVREA)
San Luis Valley
DEL NORTE
ANSEL
MOSCA JUNCTION
SARGENT
SAN LUIS VALLEY
WALSENBURG
HOMELAKE
BLANCA PEAK
ALAMOSA TERMINAL
ALAMOSA
FT GARLAND
ROMEO
ANTONITO
San Luis Valley
Substation
Project Areas
345kV Electric Transmission Line
230kV Electric Transmission Line
115kV Electric Transmission Line
69kV Electric Transmission Line
0 5 10 15 20 Miles

Other Long-Range Distribution Planning Substation Projects

Public Service, the Colorado Office of Consumer Counsel, ("OCC") and Staff of the Colorado Public Utilities Commission agreed through discussions related to Proceeding No. 14A-1002E to identify potential new distribution substation sites in rapidly growing areas. Below is a list of conceptual new substation projects under consideration by the Company. This is provided for informational purposes only. At this time, Public Service is not seeking Commission determination of the need for CPCNs for these projects or any Commission action. Most in-service dates for these projects are TBD.

Table 10. Long-Range Distribution Planning Substation Projects

Substation Project Name	Transmission Voltage	Approximate location	Potential ISD	Cost ($M)
Barker	230 kV	Across from Coors Field in Denver	2021	$29.8
Dove Valley	115 kV	Near I-25 and C-470 in Arapahoe County	2023	TBD
High Point	115 kV or 230 kV	Near Denver International Airport; Adams County	2022	$9
Titan	230 kV	Near Sterling Ranch in Douglas County	2022	$13
Stock Show	115 kV	Denver	2026	TBD
Wilson	115 kV	Loveland	TBD	TBD
Solterra	230 kV	Lakewood	TBD	TBD
New Castle	69 kV	New Castle	TBD	TBD
Superior	115 kV	Town of Superior	TBD	TBD
Sandy Creek	230 kV	Arapahoe County, near future Sandy Creek development	TBD	TBD

Additional Information

Information concerning the specific Colorado projects included in the Public Service 2020 10-Year Plan is contained in Appendix F. Additional information and supporting documentation can be found at:

http://www.transmission.xcelenergy.com/Planning/Planning-for-Public-Service-Company-of-Colorado

https://www.rmao.com/public/wtpp/PSCO_Studies.html

http://www.oatioasis.com/psco/index.html

IV. Projects of Other CCPG Transmission Providers

In addition to the projects planned by Black Hills, Tri-State, and Public Service contained in this 2020 Plan, a thorough understanding of all transmission projects planned in Colorado requires consideration of projects planned by other utilities and TPs.

Table 11. Colorado Springs Utilities Projects

In-Service	Project Name	Description	Purpose
2020	Williams Creek 230 kV Switching Station	Install a new substation on the Nixon-Claremont 230 kV line necessary to interconnect new Palmer Solar PV plant	Generation interconnection
2020	Nixon-Kelker 230 kV Line Uprate	Increase clearance on Nixon-Kelker 230 kV line to increase facility rating on the line.	Increase facility rating
2019	Cottonwood 230/115kV Autotransformer Replacement.	Install a new, upgraded 230/115 kV autotransformer at Cottonwood substation.	Increase system load serving capacity and provide compliance with the Long Lead Time Equipment requirement in the NERC Transmission Planning Standard TPL-001-4. (The existing Cottonwood auto will be refurbished and stored on site as a system spare.)

This information is provided voluntarily by CSU for the purposes of making sure the CPUC has the most complete information for planned project coordination purposes only.

Additional information concerning the specific Colorado projects included in the CSU Plan are contained in Appendix G.

Table 12. Platte River Power Authority Projects

In-Service	Project Name	Description	Purpose
2018	Boyd 230/115kV Substation Expansion	Add 230/115kV transformer T2 and reconfigure 230kV and 115kV yards to breaker-and-a-half arrangement.	Improve system reliability in the Loveland area.

This information is provided voluntarily by Platte River Power Authority ("PRPA") for the purposes of making sure the CPUC has the most complete information for planned project coordination purposes only.
Additional information concerning the specific Colorado project included in the PRPA is contained in Appendix H.

Table 13. Western Area Power Authority Projects

In-Service	Project Name	Description	Purpose
2020	Midway KV1A Replacement	Replacing KV1A at Midway	Replacing aging equipment and increasing size
2020	Ault 345/230 kV XFMR Replacement	Replacing the 345/230 kV Transformer at Ault	Increased reliability

This information is provided voluntarily by WAPA for the purposes of making sure the CPUC has the most complete information for planned project coordination purposes only.

Additional information concerning the specific Colorado projects included in the WAPA are contained in Appendix I.

V. Senate Bill 07-100 Compliance and Other Public Policy Considerations

In addition to planning for load growth and reliability, Companies must consider proposed and enacted public policies. Two of the Companies, Black Hills and Public Service, are subject to the requirements of Colorado Senate Bill 07-100 ("SB07-100") (codified at C.R.S. § 40-2-126).

Historically, the SB07-100 filings were made by Black Hills and Public Service by October 31 of each odd-numbered year. Those filings were subsequently combined into a single Proceeding with the Rule 3627 filing pursuant to Decision No. R17-0747 in Proceeding 17R-0489E, which amended Rule 3627 to require electric utilities subject to Commission rate regulation to include their transmission plans for energy resource plans specified in C.R.S. 40-2-126(2) with their transmission plans due February 1 of each even-numbered year. As stated in SB07-100, Black Hills and Public Service are required to:

a. Designate ERZs
b. Develop plans for the construction or expansion of transmission facilities necessary to deliver electric power consistent with the timing of the development of beneficial energy resources located in or near such zones
c. Consider how transmission can be provided to encourage local ownership of renewable energy facilities
d. Submit proposed plans, designations, and applications for Certificates of Public Convenience and Necessity to the Commission for simultaneous review

Black Hills and Public Service have performed transmission planning activities to comply with the requirements of SB07-100 as part of the larger, coordinated planning efforts described above. As of 2017, Colorado's ERZs remain as they were defined in the 2015 SB07-100 reports, created by consulting multiple sources of information as well as public feedback. As shown in Figure 7, Colorado's five ERZs are:

ERZ 1 (Northeast Colorado)

Includes all or part of Sedgwick, Phillips, Yuma, Washington, Logan, Morgan, Weld, and Larimer Counties. ERZ 1 presents energy development opportunities for natural gas, wind, and thermal resources.

ERZ 2 (East-central Colorado)

Includes all or part of Yuma, Washington, Adams, Arapahoe, Elbert, El Paso, Lincoln, Kit Carson, Kiowa, and Cheyenne Counties. ERZ 2 presents energy development opportunities for natural gas, wind, and thermal resources.

ERZ 3 (Southeast Colorado)

Includes all of part of Baca, Prowers, Kiowa, Crowley, Otero, Bent, and Las Animas Counties. ERZ 3 represents the potential for wind resource development.

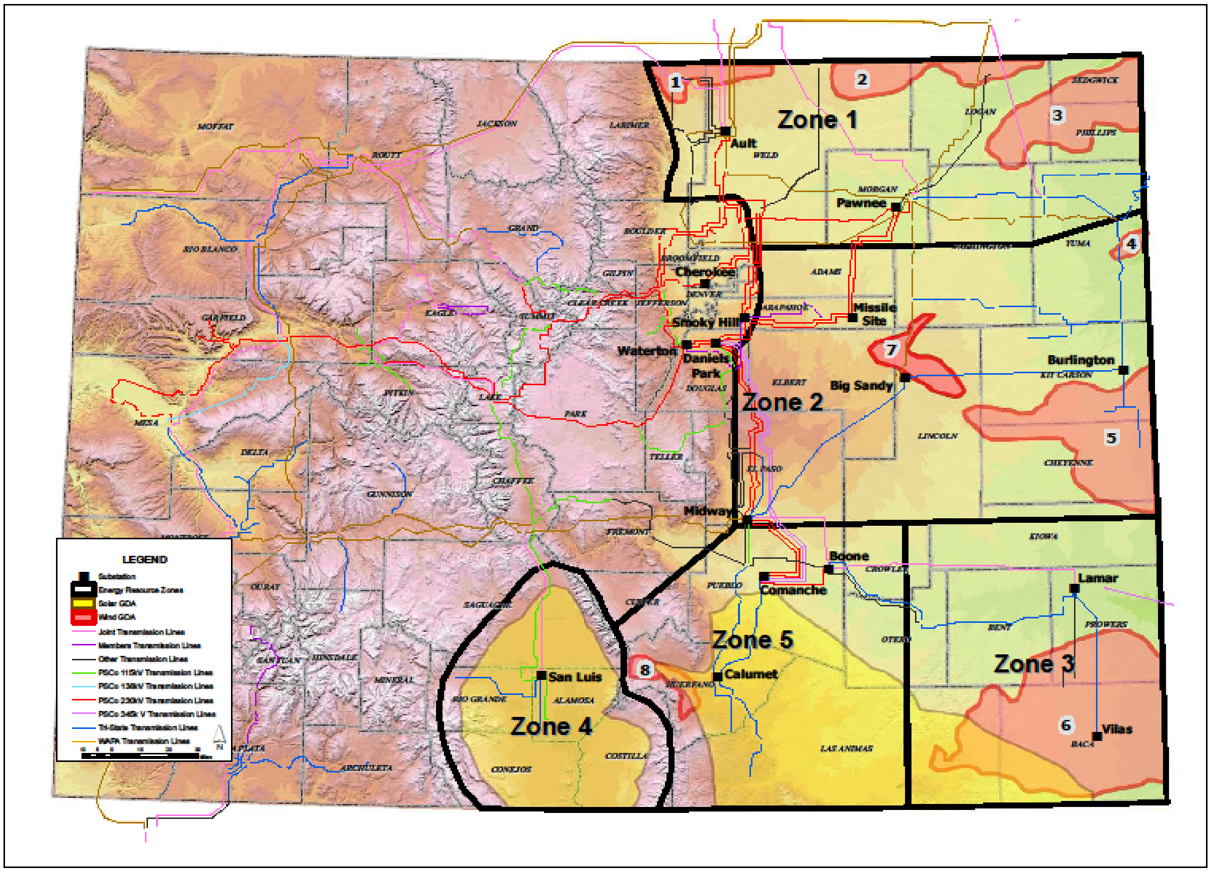
ERZ 4 (San Luis Valley)

Includes all or part of Costilla, Conejos, Rio Grande, Alamosa, and Saguache Counties. ERZ 4 presents energy development opportunities for solar resource development.

ERZ 5 (South-central Colorado)

Includes all or part of Huerfano, Pueblo, Otero, Crowley, Custer, and Las Animas counties. ERZ 5 in South Central Colorado includes the area around Pueblo and south along the I-25 corridor which includes both potential wind and solar resources.

Figure 7. Map of SB07-100 Energy Resource Zones



In addition to the public policy requirements of SB07-100, all three Companies may be subject to federal and Colorado state regulations related to carbon emission reductions from existing power plants. The Companies will continue to coordinate with each other and stakeholders with respect to the transmission planning implications of any new federal regulations and may address issues in subsequent 10-Year transmission plans.

A. Black Hills Summary

Black Hills encouraged all interested parties to participate in the 2019 SB07-100 study process. An open stakeholder SB07-100 Kick-off Meeting was held in conjunction with the Q1 Black Hills Colorado Transmission ("BHCT") Transmission Coordination and Planning Committee ("TCPC") on April 23, 2019, to inform stakeholders of the proposed study plan and to provide an opportunity for suggestions and feedback on the study process. The kick-off meeting had no external participants. A follow-up e-mail was sent on October 10, 2019, to invite stakeholders to respond with their input while updating them on the progress of the study work. Meeting notices and presentations were distributed via e-mail and posted on the Black Hills Open Access Same-Time Information System ("OASIS") page at http://www.oatioasis.com/bhct/ as well as on a Colorado SB07-100 webpage established on the Black Hills Corporation website; https://www.blackhillsenergy.com/our-company/transmission-rates-and-planning.

For the 2019 SB07-100 cycle, Black Hills selected to re-evaluate the resource injection capacity from ERZ-5, which initially was performed as part of the 2013 SB07-100 cycle. That decision was based on the completion of transmission system upgrades since that time, as well as ongoing interest to develop generation in the area as indicated by Black Hills' generation interconnection queue. The transmission system was evaluated under 2023 peak summer load levels to identify any significant adverse impact to the reliability and operating characteristics of the Western Electricity Coordinating Council ("WECC") bulk transmission system and, more specifically, to the Black Hills and surrounding transmission systems. Steady state voltage and thermal analyses examined system performance without additional projects in order to establish a baseline for comparison. Performance was re-evaluated with resource injections modeled and compared to the baseline performance to determine the impact of the injections on area transmission reliability.

The power flow analysis was performed with pre-contingency solution parameters that allowed adjustment of load tap-changing ("LTC") transformers, static VAR devices including switched shunt capacitors and reactors, and DC taps. Post-contingency solution parameters allowed adjustment of DC taps and automatically switched shunt devices, as well as adjustment of manually switched shunt devices outside the study area. Area interchange control was disabled and generator VAR limits were applied immediately for all solutions. The solution method implemented was a fixed-slope decoupled Newton solution.

Black Hills SB07-100 Conclusions

Black Hills utilized an open and transparent process in conducting its 2019 Colorado Senate Bill 07-100 study. Stakeholders were provided several opportunities for involvement and input into the study process and scope. Through this process, Black Hills believes it has fulfilled the requirements of Colorado Senate Bill 07-100, codified at C.R.S. § 40-2-126.

Baculite Mesa 115kV Substation: The 2023HS study results indicated that the BHCE transmission system could accommodate a 200MW injection at the Baculite Mesa 115kV substation with no required upgrades, assuming all planned projects are in service.

Nyberg 115kV Substation: Additionally, the study results indicated that the BHCE transmission system could accommodate a 75MW injection at the Nyberg 115kV substation. Higher levels of injection into this substation caused overloads on XCEL's Boone 230/115kV transformer during a P2 breaker failure contingency at Nyberg.

South Fowler 115kV Substation: The analysis also looked at injections at the planned South Fowler 115kV substation. The results indicated that the BHCE transmission system could accommodate at 75MW injection at this location. Higher levels of injection into this substation caused overloads on XCEL's Boone 230/115kV transformer during a P2 breaker failure contingency at Nyberg. The breaker failure at Nyberg cuts off the only 115kV paths to the west portion of BHCE's system. This forces the power through the Boone 230/115kV transformer.

West Station 115kV Substation: The last injection point that was included in the analysis was the West Station 115kV substation. The results indicated that the BHCE transmission system could accommodate a 175MW injection at this location. High levels of injection caused overloads on the Fountain Valley – Midway 115kV transmission line. These results included the planned rebuild rating for this line. Increasing this rating further would require substantial terminal equipment upgrades at the Midway substation.

Designate Energy Resource Zones

On November 24, 2008, Public Service filed with the Commission an information report that identified its five ERZs within Colorado. Four of the ERZs identified by PSCo are located in close geographical proximity to the Black Hills system, specifically ERZs 2, 3, 4 and 5. In the 2011 SB07-100 study report, Black Hills identified two ERZs (ERZ-1 & ERZ-2), both of which were located within the PSCo defined ERZ-5. In order to avoid confusion, Black Hills has adopted the five PSCo defined ERZs within Colorado.

Develop plans for the construction or expansion of transmission facilities necessary to deliver electric power consistent with the timing of the development of beneficial energy resources located in or near such zones.

Black Hills identified the impacts of the various resource scenarios on the Black Hills transmission system and identified projects that ensure reliable delivery of beneficial energy resources from the designated ERZ-5 to customer loads.

Consider how transmission can be provided to encourage local ownership of renewable facilities, whether through renewable energy cooperatives as provided in Colo. Rev. Stat. § 7-56-210, or otherwise.

The identified new transmission projects will facilitate renewable resource development in ERZ-5 in excess of Black Hills' forecasted resource needs. The studied resource injections are in relatively close proximity to Black Hills customers and would be facilitated by a direct physical connection to the Black Hills electric system.

Submit proposed plans, designations, and applications for Certificates of Public Convenience and Necessity to the Commission for simultaneous review.

Black Hills believes that the 115 kV transmission projects it has identified to facilitate the reliable delivery of beneficial energy resources to customer load are "in the ordinary course of its business" and do not require CPCNs, pursuant to Colo. Rev. Stat. §§ 40-2-126(3) and 40-5-101. The resource injection amounts identified in this report are indicative of potential system performance under the evaluated scenarios, but should not be construed to reflect firm system capability. In-depth analysis and coordination is required to establish a more comprehensive projection of potential system performance following implementation of the identified system upgrades.

B. Public Service Summary

Public Service began filing SB07-100 reports in October 2007. Public Service has developed plans for nine transmission projects to expand transmission capability for the delivery of beneficial energy resources from ERZs. These projects are listed in Table 14.

Public Service has completed the first five projects listed in Table 14. These projects have enabled Public Service to interconnect 1400 MW of wind in eastern and northeastern Colorado, and accommodates an additional 600 MW of wind from the Rush Creek Wind Project. The table below lists the name of the project, the ERZ that the project would serve, and a tentative schedule for implementation. The status of the projects that remain planned or conceptual are described in more detail in Section III.

Table 14. Public Service SB07-100 Projects

	Project	ERZ	ISD	Status
1	Missile Site 230 kV Switching Station	2	2010	Project placed in-service November 2010.
2	Midway-Waterton 345 kV Transmission Project	3,4,5	2011	CPCN granted on July 16, 2009. Project placed in-service May 2011.
3	Pawnee-Smoky Hill 345 kV Transmission Project	1,2	2013	CPCN granted on February 29, 2009. Project placed in-service June 2013.
4	Missile Site 345 kV Substation	2	2012	CPCN granted on June 8, 2010. Project placed in-service December 2012.
5	Pawnee-Daniels Park 345 kV	1,2	2019	CPCN granted on April 9, 2015. Project placed in service December 2019.
6	Lamar-Front Range 345 kV	2,3	TBD	Plan being re-evaluated through CCPG. Certain segments may be implemented in a phased approach.
7	Lamar-Vilas 230 kV	3	TBD	(See Lamar – Front Range)
8	Weld County Expansion	1	TBD	Studies ongoing through CCPG
9	San Luis Valley	4,5	TBD	Studies Complete

1. *Projects That Have Been Completed or Planned*

Missile Site 230 kV Switching Station (ERZ-2)

The Missile Site 230 kV Switching Station Project consisted of a new switching station near Deer Trail, Colorado, that connects the existing Pawnee-Daniels Park 230 kV transmission line into and out of the Missile Site 230 kV Switching Station. The project has allowed interconnection of new generation in ERZ-2.

The Missile Site 230 kV Switching Station was placed in-service in November 2010. Public Service interconnected the 250 MW Cedar Point wind project in 2011.

Missile Site 345 kV Switching Station (ERZ-2)

The Missile Site 345 kV Substation expanded the Missile Site 230 kV Switching Station to allow additional generation and transmission interconnections from ERZ-2 at the 345 kV voltage level. The substation bisects the Pawnee-Smoky Hill 345 kV Transmission Project. In addition to connecting the Pawnee-Smoky Hill 345 kV line, the substation also allows for future 345 kV transmission connections. These include connections to the Pawnee-Daniels Park 345 kV Project. The Missile Site 345 kV Substation was placed in-service in December 2012. The Limon Wind Energy Center brought about 600 MW of wind generation into Missile Site in 2014, and in 2018, the Rush Creek Project added another 600 MW. The Bronco Plains and Cheyenne Ridge projects will interconnect another 800 MW in 2020.

Midway-Waterton 345 kV Transmission Project (ERZs 3, 4, and 5)

The project consists of 82 miles of 345 kV transmission line from the Midway Substation, near Colorado Springs, to the Waterton Substation, southwest of Denver. The Midway-Waterton 345 kV project accommodates additional generation resources in ERZs 3, 4, and 5. The Midway-Waterton 345 kV Transmission Project was placed in-service in May 2011.

Pawnee-Smoky Hill 345 kV Transmission Project (ERZs 1 and 2)

This project consists of developing approximately 95 miles of 345 kV transmission line between the Pawnee Substation near Brush, Colorado, and the Smoky Hill Substation, east of Denver. The project allowed for additional resources in ERZ-1 and ERZ-2, interconnected at or near the Pawnee and Missile Site substations. The project was designed to facilitate construction of the Pawnee-Daniels Park 345 kV Project. This project was placed in-service in June 2013.

Pawnee-Daniels Park 345 kV (ERZs 1 and 2)

The Pawnee-Daniels Park 345 kV Transmission Project is described in Section III.C.2. The project consists of building a 125-mile 345 kV transmission line from the Pawnee Substation in northeastern Colorado to the Daniels Park Substation, south of the Denver-Metro area. The project also will result in constructing a new Harvest Mile 345 kV Substation, near Smoky Hill Substation, and a new Harvest Mile-Daniels Park 345 kV line. The project also will interconnect with the Missile Site 345 kV Substation. This project was planned in accordance with Senate Bill 07-100, in that it will accommodate generation in designated Energy Resource ERZs 1 and 2. The project was placed in-service in December 2019, at an estimated cost of $169.4 million.

2. *Projects that are Planned or Conceptual*

The projected in-service dates of these conceptual projects identified in Table 13 above can be affected by CPCN approval, revisions to load forecasts, resource plans, siting and land permitting, coordination of construction outages, and material delivery times. Because all of these projects are presently in the conceptual stage, assessments will continue on whether the stated factors will cause any modifications to these projects, in terms of configuration, timing, or otherwise.

Lamar-Front Range 345 kV (ERZs 2 and 3)

This project is described in Section III.C.2 and was planned as a high voltage project that covered vast portions of eastern Colorado to accommodate resources in ERZs 2 and 3. The original Lamar-Front Range project was estimated to cost approximately $900 million. Recently, Tri-State and Public Service have been planning and implementing projects that align with the original Lamar-Front Range plan. These include the Tri-State Burlington-Lamar 230 kV line and the Public Service Missile Site – Cheyenne Ridge 345 kV line.

Also, since 2019, the CCPG LFRTF has been re-evaluating how the Lamar – Front Range plan might be modified, based on recent changes and plans to the transmission system in Colorado. As mentioned in the Public Service 10-Year Plan Overview, a plan evaluated by the LFRTF that shows technical merit and could meet Public Service SB07-100 and SB19-236 Clean Energy Plan objectives includes the following components:

- Networking the Missile Site – Cheyenne Ridge 345 kV line to Burlington
- New 345 kV transmission from Burlington – Lamar – Comanche
- New 345 kV transmission from Burlington – Missile Site
- New 345 kV transmission from Burlington - Pawnee

Lamar-Vilas 230/345 kV (ERZ-3)

The Lamar-Vilas project has been associated with the Lamar-Front Range Plan. The Lamar-Vilas line could consist of approximately 60 miles of high-voltage transmission from Lamar Substation to the existing Vilas Substation to provide access to additional resources in ERZ-3 and Baca County.

Weld County Transmission Expansion (ERZ-1)

This plan is described in Section III.B.2 as a means to accommodate additional generation resources in ERZ-1. As a result of the potential for load growth and the Public Service plan to replace aging 44 kV infrastructure in the area, other projects have been planned and are being developed in the area that align with, and may ultimately replace the Weld County Expansion Project. Public Service is implementing the Ault-Cloverly 230/115kV Project and Tri-State is implementing the planned SWEP, which may connect transmission from the Denver-Metro area to the south of Greeley system. The CCPG NECO Subcommittee has been working to develop a comprehensive transmission plan for Northeast Colorado to serve a variety of needs. Studies indicate that a Weld-Rosedale 230 kV line and a Rosedale Box Elder - Ennis 115 kV

Transmission Lines would be a prudent next step to meet the objectives. The Weld County Expansion could be a combination of the planned Ault-Cloverly Project, and SWEP and conceptual Weld-Rosedale-Box Elder - Ennis 230 & 115 kV lines, or the Weld County Expansion may be a new project that could be considered as a third or eastern phase of the planning efforts in the area.

When specific projects have been recommended, Public Service will inform stakeholders and develop plans for implementation.

San Luis Valley (ERZs 4 and 5)

This plan has been described in Section III.B.2 and has been planned as a means to accommodate potential generation from ERZs 4 and 5, in addition to improving the reliability of the transmission system in the San Luis Valley area of Colorado. Studies were performed in the CCPG San Luis Valley Subcommittee, which identified that additional 230 kV transmission from San Luis Valley to Poncha to the Front Range would enable additional resource accommodation. As specific projects are planned and recommended, Public Service will inform stakeholders and develop plans for implementation.

VI. Stakeholder Outreach Efforts

Per Rule 3627(g), “Government agencies and other stakeholders shall have an opportunity for meaningful participation in the planning process.” “Government agencies include affected federal, state, municipal and county agencies. Other stakeholders include organizations and individuals representing various interests that have indicated a desire to participate in the planning process.” *See* Rule 3627(g)(I). The following sections summarize each Company's approach to government agency and stakeholder outreach and participation pertaining to Rule 3627. Processes specific to the stakeholder input directives of FERC Order No. 890 are discussed in Section VII.D.

A. Black Hills Outreach Summary

Black Hills recognizes the importance of stakeholder involvement throughout the transmission planning process and considers a stakeholder to be any person, group or entity that has an expressed interest in participating in the planning process, is affected by the transmission plan, or can provide meaningful input to the process that may affect the development of the final plan.

Stakeholders are encouraged to participate in Black Hills’ transmission planning through the regular meetings held by the TCPC as part of the annual study process under FERC Order No. 890. The TCPC is an advisory committee consisting of individuals or entities who are interested in providing input to Black Hills’ Transmission Plan. The TCPC study process consists of a comprehensive evaluation of the Black Hills and surrounding transmission systems for critical scenarios throughout the 10-year planning horizon. Stakeholders are notified of the initial meeting at the start of the study cycle and invited to participate. An opportunity is provided to comment on the scope of the study at this point in the process. Relevant system modeling data is requested from the stakeholders, as well as any economic study or alternative scenario requests. Once the study cases are compiled, another open stakeholder meeting is held to review and finalize the data and study scope. A third stakeholder meeting is held to review preliminary study results and discuss potential solutions to any identified problems. This process allows the TCPC to develop a comprehensive transmission plan to meet the needs of all interested parties. A final stakeholder meeting is held to approve the study report and Local Transmission Plan ("LTP"). Following each meeting, contact information for the transmission planner performing the study is provided to allow for ongoing questions or comments regarding the study process. Updates on the progress of the TCPC study efforts also are provided to regional planning groups, such as the CCPG, to promote involvement from a larger stakeholder body.

A list of potential stakeholders was created during the initial TCPC study cycle and has continued to evolve through active invitations, recommendations from existing participants, and outreach at CCPG meetings. Black Hills is continually modifying its stakeholder list in order to invite a more comprehensive group of participants into the transmission planning process.

Two quarterly meeting invites were sent in 2019 as part of Black Hills' annual TCPC process. The primary kick-off taking place on April 23, 2019, and a second invite on October 10, 2019. Meeting notifications were sent to the stakeholder contact list, announced at the CCPG meetings and posted on Black Hills' OASIS web page.

Black Hills' Q1 stakeholder meeting is typically more educational in nature and was held via web/phone conference on April 23, 2019. It served the purpose of presenting the transmission planning process to stakeholders, describing the scope of the 2019 assessment, reviewing the current 10-Year Transmission Plan and soliciting feedback on the study scope, the stakeholder outreach process, and potential alternatives to the projects within the 10-Year Plan.

Black Hills' Q3 stakeholder meetings were sent out via e-mail on October 10, 2019. This meeting served the purpose of an update and solicitation for feedback regarding the progress of the study and conclusions. Although there were no updates made since the kick-off meeting, this invite was to allow any part to request a meeting if it was deemed necessary. No interest was shown to pursue an official meeting after the invite was sent.

Black Hills' Q4 stakeholder meeting was not held, as cases from CCPG were not received until the week of December 20, 2019. At that time, an e-mail was sent to stakeholders presenting our updated study scope and list of scenarios included for stakeholder question and comment. The study work has been started and results will be presented at the 2020 Q1 stakeholder meeting.

A limited number of external stakeholders attended the quarterly meetings. The stakeholder meetings produced some dialog on specific projects, but substantive feedback regarding the planning process and future projects was not received. Black Hills relied heavily on coordination with affected utilities and internal review of alternatives to ensure that the projects selected and presented in the Rule 3627 Transmission Plan were optimal and adequate for the needs of its network transmission system and Colorado's goals of fostering beneficial energy resources to meet load growth.

For more information regarding the stakeholder process utilized in the 2019 or earlier Black Hills TCPC planning processes, including meeting notices, notes, presentations and contact information, refer to the Black Hills' Transmission Planning page; https://www.blackhillsenergy.com/our-company/transmission-rates-and-planning
Stakeholder outreach information also is available in the Transmission Planning folder on the Black Hills OASIS at: http://www.oatioasis.com/bhct

B. Tri-State Outreach Summary

Tri-State performs transmission planning-related stakeholder outreach as a standard part of its day-to-day business consistent with its policy of planning in an open, coordinated, transparent and participatory manner. This outreach encompasses various efforts including: Rule 3627 specific meetings and stakeholder communications; FERC Order No. 890 specific meetings and communications; project-specific meetings and communications; and CCPG participation.

As described in Rule 3627(g)(I), stakeholders include federal, state, county, and municipal government agencies as well as other non-governmental organizations and individuals having an interest in the transmission planning process. Tri-State identifies potential governmental stakeholders based generally on a five-mile area surrounding proposed transmission facilities. Federal agencies in the areas of the transmission projects included in Tri-State's 2020 10-Year Transmission Plans typically include the Bureau of Land Management, the U.S. Forest Service, the National Park Service, and the Department of Defense. Potentially interested state agencies include the Colorado State Land Board and associated Stewardship Trust Lands, and the Colorado Division of Parks and Wildlife. Outreach to county and local governments typically includes communications to relevant elected officials as well as administrators, managers, and land planning, economic development, and legal staffs. In some instances, Tri-State's governmental outreach also included agencies such as parks and school districts.

Contact lists for non-governmental stakeholders were developed through various transmission planning forums such as CCPG and other WestConnect planning groups, as well as individuals and organizations that have participated in previous Tri-State stakeholder meetings. When known, Tri-State also included stakeholders identified as being interested in specific proposed projects. The resulting non-governmental stakeholders included other utilities, Tri-State Member Systems, energy and transmission project developers, environmental groups, economic development organizations, various advocacy groups, and elected officials not already included in the governmental outreach communications.

In 2019, Tri-State hosted one transmission planning-related stakeholder outreach meeting in connection with development of the 2020 10-Year Transmission Plan. The meeting was on August 21, 2019, and provided a summary of new information related to Tri-State's ongoing transmission planning activities as well as updates on current projects and coordination with CCPG's long range transmission planning efforts. This meeting also constituted Tri-State's FERC Order No. 890 stakeholder meeting and provided an opportunity for stakeholders to provide input in connection with all of Tri-State's long-range transmission plans. All such input and relevant alternatives were considered and included in the appropriate biennial transmission plans submitted to the Colorado Public Utilities Commission pursuant to Rule 3627. No alternatives were proposed at this meeting.

In addition to this larger stakeholder meeting addressing system-wide and Colorado-specific transmission projects, Tri-State also conducted a number of meetings related to individual proposed transmission projects. These meetings and other project-related communications included relevant government agencies, economic development entities, and other interested organizations and persons to inform them of the proposed project and provide an opportunity for feedback and consideration of potential alternatives. The nature and timing of outreach efforts related to specific projects was generally dependent on the development status of the project.

Details of Tri-State's meetings, including a list of attendees and a meeting presentation video which includes questions and comments received together with Tri-State's responses thereto, and relevant presentations can be found at:
http://www.tristategt.org/stakeholder-outreach

Tri-State also participates in the CCPG's transmission planning efforts. As discussed in Section VI.D. of this Plan, the CCPG planning process includes additional stakeholder outreach and a further opportunity for stakeholder participation in and input into the overall Colorado coordinated transmission planning process, which includes Tri-State's proposed projects. Additional information concerning CCPG stakeholder opportunities is available at the WestConnect website.

Tri-State confirms that, as required by Commission Rule 3627(g)(V), this 2020 10-Year Transmission Plan is available to all government agencies and other stakeholders through Tri-State's Transmission Planning website at: *http://*www.tristate.coop/transmission-planning

Tri-State has informed all stakeholders of the availability of the 2020 10-Year Transmission Plan.

C. Public Service Outreach Summary

Rule 3627 requires a summary of stakeholder participation and input and how this input was incorporated in the transmission plan. The rule states that government agencies and other stakeholders shall have an opportunity for meaningful participation in the planning process. The government agencies include affected federal, state, municipal and county agencies. In addition, Rule 3627 provides that other stakeholders, including organizations and individuals representing various interests that have indicated a desire to participate in the planning process, must also have an opportunity for meaningful participation. Under Rule 3627, Public Service is required to actively solicit input from the appropriate government agencies and stakeholders to identify alternative solutions. In addition to the Public Service outreach efforts listed below, the Company actively participates in numerous CCPG groups, where it also engages with and responds to comments presented by stakeholders. The following is a synopsis of the outreach that the Company performed relevant to this rule. Also, Appendix K lists some responses to comments received from two stakeholders.

Rule 3627 Webinars

The Company developed an informational PowerPoint presentation that included information on the long-range plans developed as part of Rule 3627. Two, two-hour-long webinars were held – the first on Friday, August 16, 2019, and the second on Wednesday, September 11, 2019 - to give stakeholders opportunity to participate and comment on transmission plans, either in person (at the Xcel Energy offices in downtown Denver) or via the Internet. E-mail invitations with exact verbiage will be provided at the request of the Commission.

More than 500 individuals representing the following stakeholder groups—including all state legislators in both the House and Senate—received invitations to the webinars:

- Elected officials
- Federal, state and local government officials
- Environmental groups
- Energy developers
- Chambers of commerce
- Business and industry
- Planning and economic development agencies
- Large energy users
- Citizens and advocacy groups
- Intervenors on past PSCo filings
- Organizations involved in transmission planning (*e.g.*, CCPG members)

Invitations also were sent to the CCPG's distribution list, which includes representatives from other utilities including Black Hills, WAPA and Tri-State, as well as stakeholders representing environmental interests, consulting firms, law firms, and other individuals and groups. Local government elected officials, including county commissioners in counties that could be impacted by projects in the Public Service's portion of the 2020 Plan, were also invited along with local planning office representatives and other staff officials from local governments and agencies. Because routing had not been started on some of these projects, which were still in the planning phase, individual landowners who might be impacted were not identified.

Information on Xcel Energy's transmission projects in Colorado was provided to all invitees via a link in the e-mail, but since then, the web address was redirected to the following: http://www.transmission.xcelenergy.com/Projects/Colorado

Attendance at the August 16, 2019, session included eight in-person attendees external to PSCo and approximately 60 webinar attendees, although an actual count was difficult to gauge, as participant count decreased and increased during the course of the presentation. Since self-identification was optional, it was not possible to determine whether additional participants entered the webinar or participants already in attendance reconnected after becoming disconnected from the webinar. Attendance at the September 11, 2019, session included five in-person attendees external to Public Service and approximately 20 webinar attendees.

The PowerPoint presentation discussed at the session consisted of three basics parts. Because the level of knowledge surrounding transmission and transmission planning of the attendees was not known, part one provided an overview of electric transmission to acquaint attendees with basic information about how the system works and what constitutes the transmission system. Part two covered the transmission planning process, provided an overview of how and why planning is done, and outlined the many factors that are considered when developing plans. Part three reviewed all projects included in Public Service's portion of the 2020 Plan. Public comment from the webinar covered a wide range of topics. Written comments were received from the Office of Consumer Council and Western Resource Advocates. The written comments and Public Service responses to these comments are included in Appendix K.

FERC Order 890 Stakeholder Meetings

The Company facilitates two open stakeholder meetings per year to meet the requirements of FERC Order 890. The meetings are held in the first and fourth quarters every year at the Xcel Energy office in Denver, and the content is very similar to that presented in the Rule 3627 webinars. In the last two years, FERC Order 890 meetings were held on March 15, 2018, December 5, 2018, March 20, 2019, and December 4, 2019. Public Service has taken a similar approach to Tri-State, where the Rule 3627 and FERC Order 890 meetings are referred to as open stakeholder meetings that will

meet the objectives of both rules. Meeting agendas, presentations (referred to as "Transmission Plans", and notes are available at:
http://www.oatioasis.com/psco/index.html under "FERC 890 Postings".

PROJECT-SPECIFIC OUTREACH

Pawnee-Daniels Park Project

The Pawnee-Daniels Park Project was energized on December 26, 2019. Final site restoration and revegetation work will continue throughout spring and summer 2020. Public Service will continue to work with landowners and impacted communities throughout the remainder of restoration activities.

Avery Substation Project

Public Service is proposing to construct the Avery Substation and Transmission Line project. The new Avery Substation will enable the company to serve existing and new load in the vicinity of Timnath, Severance and Windsor along the eastern side of the Interstate 25 corridor. Avery Substation will assist in providing back up to the existing Cobb Lake and Windsor Substations, which are reaching their capacity. It also will provide reliability to our existing and future customer load. The project consists of a new electric distribution substation, an associated overhead double-circuit 230 kV electric transmission line and overhead distribution feeder lines near the towns of Windsor, Severance and Timnath, Colorado. Power for the proposed 1.4-mile 230 kV transmission line will be provided by interconnecting the existing PRPA Timberline-Ault 230 kV transmission line. Public Service is currently evaluating in the land use permitting process with the Town of Windsor for the substation and a portion of the transmission line. Land use permits for other portions of the transmission line have been approved. This connection will supply the proposed Avery Substation with the electrical supply needed to power the distribution feeders serving the immediate communities.

Land use permitting for portions of the transmission line in unincorporated Weld County was completed in September 2018. A Conditional Use Grant application for the substation and the last half-mile of line was submitted to the Town of Windsor in December 2018. Hearings were held at the Windsor Planning Commission and Town Board in February 2019. The Town Board continued the hearing due to questions about the location and information needed from the landowner. Based on landowner feedback, Public Service decided to withdraw the application and attempt to resolve the primary concerns from the public and the town. This resulted in a new site alternative that was presented to the public at an open house on July 9, 2019.

Based on feedback at the open house, the new site was chosen as the preferred location and a new application was submitted on August 27, 2019, with this proposed site.

The Conditional Use Grant was recommended for approval by the Planning Commission on November 6 and was approved by the Town Board on November 25, 2019. It is anticipated that construction on the substation will commence at the end of Q1 or beginning of Q2 2020. Public Service staff will conduct public outreach as needed to support construction.

Ault-Cloverly 230/115 kV Transmission Project

The Ault-Cloverly 230/115 kV Transmission Project will increase electric reliability and load-serving capability of the Xcel Energy electric transmission system in and around the Greeley area, and will provide accommodation for new generation resources in the region while aligning with other transmission planning efforts in the area. The company filed a CPCN application with the CPUC on March 9, 2017, to construct the Northern Colorado Area Plan; Proceeding Number 17A-0146E.

The company held three open house meetings for the Northern Colorado Area Plan in 2018, and submitted a 1041 permit application in November 2018. Following several public comments voicing opposition to the southwestern portion of the preferred route, the company amended its application to include the WAPA/Ault to Husky to Graham Creek portion of the line, with the intention of applying for a separate permit for the Graham Creek to Cloverly portion of the line. On June 18, 2019, the Weld County Planning Commission unanimously recommended denial to the Board of County Commissioners. Following this denial, the company determined the best course of action would be to withdraw the 1041 permit application. The company is now starting over with a new siting and community engagement effort. In the coming months, we will be hosting a Community Working Group, consisting of 12 to 20 community members and leaders to participate in the routing effort. Additionally, the second of four planned open house meetings (the first meeting was held in November 2019) will be hosted in late January in the town of Eaton. The 1041 Areas and Activities of State Interest land use permit application will be submitted in late spring/summer 2020, with Planning Commission and Board of County Commissioner hearings taking place in summer/fall 2020.

Greenwood - Denver Terminal

The Company is proposing the upgrade of approximately 15.4 miles of existing transmission facilities to 230 kV by rebuilding and/or reconductoring existing transmission facilities from the Greenwood Substation to the Denver Terminal Substation within existing right-of-way (ROW). The CPCN submittal for the project is targeted for early 2020. The project is located in six different jurisdictional boundaries: Centennial, Greenwood Village, Littleton, Englewood, Sheridan and Denver.

Outreach activities completed to date have been with elected officials and planning staff. The list below summarizes meetings that have taken place to date:

- September 16, 2019 – City of Englewood City Manager
- September 23, 2019 – City of Centennial Councilmembers
- September 25, 2019 – City of Greenwood Village Mayor and City Manager
- September 27, 2019 – City of Littleton staff
- October 3, 2019 – City of Sheridan City Manager and staff

- October 4, 2019 – City of Greenwood Village staff
- October 9, 2019 – City of Centennial Mayor and City Manager
- The City of Denver Council members were notified informally by the Company Area Manager
- November 4, 2019 – City of Littleton School District
- November 6, 2019 – City of Centennial City Planner and Public Works
- November 11, 2019 – City of Englewood City Planner and Public Works
- January 7, 2020 – Pre-Submittal Application submitted to City of Denver Planning and Development
- February 11, 2020 – Scheduled informal presentation at City of Littleton City Council public hearing.

Future meetings with the City of Englewood elected officials and the staff of the remaining cities are being scheduled. Public meetings, including open houses and neighborhood associations, will be held in February 2020.

Barker Substation

The Company is proposing the installation of equipment in the currently empty Barker Substation site and a new double circuit buried transmission line from the Barker Substation to the existing LaCombe Substation. The project is located within the City of Denver and outreach to the city is anticipated to begin in January 2020.

Glenwood-Rifle Transmission Line

In 2019, Public Service staff met with Glenwood Springs city management to discuss the Glenwood to Mitchell Creek Transmission Line Rebuild project. The Project consists of rebuilding approximately two miles of 69kV transmission line to 115kV transmission line, which will be initially operated at 69kV. Currently, the team is evaluating alternatives that include rebuilding outside of the existing alignment due to vegetation and ROW constraints in the current alignment. Public outreach is planned to begin in 2020, with a public open house and communications with elected officials tentatively planned in the first quarter of 2020.

Cheyenne Ridge Wind Farm and 345 kV Transmission Line Project

The Cheyenne Ridge 500 MW wind farm and 73-mile 345 kV transmission line is one of the projects that makes up a portion of the company's Colorado Energy Plan. The project is located in Lincoln, Kit Carson and Cheyenne counties, and, when complete, will generate enough renewable energy to power 270,000 homes. The company completed its purchase of the project asset from Tradewind Energy, who developed and permitted the project, in June 2019.

During the development phase of the project, Tradewind Energy engaged with many stakeholders, including county planning staff, landowners, Colorado Division of Wildlife, Colorado Department of Public Health and Environment, the Nature Conservancy, United States Fish and Wildlife Service, Colorado Department of Transportation, and the Colorado State Historic Preservation Office. After the company's purchase of the project, engagement with these stakeholders has continued.

The project commenced construction in July 2019 and is expected to reach commercial operations in December 2020. Since taking ownership of the project in June 2019, the company has sent a brochure on project updates to stakeholders and landowners. The brochure contains an update of the construction activities that have occurred to date and a high-level project schedule. The company also is hosting a project website that provides project updates, project photos, and contact information for questions and concerns. The website can be found at the following URL:
https://www.xcelenergy.com/energy_portfolio/renewable_energy/wind/co_wind_power/cheyenne_ridge_wind_project

The Company plans to continue stakeholder engagement in 2020 with the issuance of future project brochures, updates to the project website, landowner liaison efforts, and coordination with Lincoln, Kit Carson and Lincoln counties, and the Colorado Department of Transportation.

D. CCPG Outreach Summary

To ensure stakeholders in Colorado have multiple opportunities to provide input and receive a broader perspective on the evolution of Colorado's transmission system, TPs also leverage the CCPG stakeholder input process in developing the 10-Year transmission plan. CCPG has a subgroup called the 3627 Subcommittee. The Subcommittee serves as a forum for coordination among the Colorado electric utilities that are required to comply with PUC Rule 3627, and for receipt and consideration of stakeholder proposals submitted in connection with 10-Year transmission plans. Since the 2012 filing, TPs have worked with CCPG to formalize and document processes for receiving, evaluating, and providing feedback on stakeholder submitted alternatives. Stakeholders are provided opportunities for meaningful participation through multiple channels, including an online form that can be emailed, by participating in open meetings via teleconference, or by actively attending quarterly meetings. Full documentation of the process by which stakeholder input, suggestions, and alternatives are to be categorized, evaluated, and recorded is included in Appendix J as well as on the CCPG website at:
http://regplanning.westconnect.com/ccpg_stakeholder_opportunities.htm

Generally, the process is initiated by the stakeholder filling out a form and supplying it to the CCPG chair. The form requests the following information:

- Study or project name
- New study or alternative
- Narrative description
- Study horizon date
- Geographic footprint of interest
- Load and resource parameters
- Transmission modeling
- Suggested participants
- Policy issues to address

- Type of study
- Other factors

Once the CCPG chair receives the request, a determination will be made as to whether adequate information has been provided. The chair may contact the requester to ask for additional details. The chair will facilitate an ad-hoc review group ("Review Group") to review and categorize the request. The Review Group will determine:

- If the request is reasonable from a reliability planning perspective.
- Who should be responsible? (CCPG or a smaller sub-group of CCPG; or should the study be forwarded to a larger group such as WestConnect or WECC)?
- The likely schedule for completing the analysis requested.

The Review Group may consider the following questions to determine the response to the request:

- Which portion(s) of the CCPG transmission system shall be under consideration in the study?
- Would the request be of interest to multiple parties?
- Does the request raise policy issues of national, regional, or state interest?
- Can the objectives of the study be met by existing or planned studies?
- Would the study provide information of broad value to customers, regulators, transmission providers and other interested Stakeholders?
- Does the request require an economic (production cost) simulation or can it be addressed through technical studies, (power flow and stability analysis)?

Once the Review Group has determined that the request is reasonable and has verified the purpose and intent of the request, a written response will be developed and provided to the requester and CCPG.

If the Review Group determines that the request cannot be accommodated by CCPG or any TP, an explanation will be provided. If the Review Group determines that the request can be accommodated, then the response will provide information as to the recommended logistics for how the request will be handled, including the responsible parties and a schedule for completion. CCPG maintains a record of all comments and requests received, as well as their disposition. These records also will be posted on the CCPG section of the WestConnect website.

CCPG Northeast Colorado Subcommittee Stakeholder Input Process

The CCPG NECO Subcommittee is the forum for coordinated planning of the transmission system that generally covers Weld, Morgan, Adams, Washington, Logan, Sedgwick, Phillips and Yuma counties and also extends to portions of Boulder and Larimer counties. The objective of the NECO Subcommittee consists of developing transmission plans that will support and facilitate load growth, allow for future generation injection, coordinate with reliability improvements in the Greeley area, and complement other longer-term transmission plans in northeast Colorado. In 2017, the group recommended the Ault – Cloverly 230/115 kV project as the Northern Greeley Area Plan (NGAP).

Public Service filed for a CPCN for the Northern Greeley Area Transmission Plan Project in 2017 and the NECO Study Report was included in the testimony. On March 1, 2018, a CPCN was granted in the Recommended Decision by the Public Utilities Commission for the Proceeding No. 17A-0146E.

In 2017-2019, the NECO Subcommittee changed its focus to the transmission system south of Greeley. The objectives are similar to the north of Greeley studies, which are to reliably replace the existing 44 kV system, increase the ability to accommodate future load growth, allow for beneficial resource development and align with other transmission projects in the area.

In 2018-2019, the NECO Subcommittee met on:

- May 2, 2018
- June 6, 2018
- July 17, 2019

The subcommittee has performed studies to evaluate the present load-serving and generation interconnection capabilities. At least 11 alternatives were evaluated. Presently, the alternative that meets not only the NECO objective, but also can assist with the Public Service 80x30 objectives appears to be a new 230 kV line from Weld – Rosedale, and a 115 kV line from Rosedale – Box Elder – Ennis.

Colorado Energy Plan Task Force

The Colorado Energy Plan Task Force (CEPTF) was formed to inform stakeholders of the studies being performed to evaluate the Company's 2016 ERP and 2017 CEP. Public Service chaired and performed the study work for the CEPTF.

The following stakeholders participated in the CEPTF:

- Basin Electric Power Company
- Black Hills Corporation
- Bright Energy Storage
- Buckyball Systems
- Colorado Public Utilities Commission
- Colorado Springs Utilities
- Dietze & Davis
- Intermountain Rural Electric Association
- Lucky Corridor
- Tormoen Hickey LLC
- Colorado Office of Consumer Council
- Western Area Power Administration
- Western Resource Advocates

- Tri-State
- TradeWind Energy

Meetings were held on:

- November 1, 2017
- November 27, 2017
- March 8, 2018
- October 18, 2018
- March 1, 2019
- July 17, 2019

The CEPTF provided a forum to inform stakeholders of key findings and recommendations related to the transmission issues associated with implementation of the CEP Portfolio, which include:

- There are no significant transmission deficiencies caused directly by the retirement of Comanche Units 1 & 2. The system will remain reliable and there are no transient stability issues.
- Implementation of the CEP Portfolio requires additional voltage control facilities and a network upgrade in the Denver metro area.
- The voltage control facilities include a mix of static and dynamic devices that are needed to maintain adequate voltage performance.
- The recommended network upgrade consists of a new Greenwood Denver Terminal 230 kV line. At least eight transmission alternatives were evaluated based on stakeholder input.

CCPG Lamar Front Range Stakeholder Input Process

In 2019, the Lamar-Front Range Task Force (LFRTF), which was facilitated by Tri-State, revisited the Lamar-Front Range studies completed in 2013. In 2013, the Lamar-Front Range plan was identified through extensive transmission analysis to facilitate addition of new resources in eastern Colorado, improve transmission system reliability, and increase operational flexibility. The 2013 plan was conceived as a joint project between Public Service and Tri-State. A primary driver for Public Service was to meet an SB07-100 objective to plan transmission from the ERZ-3. The overall plan included the following transmission components:

- Two 345 kV transmission circuits between Lamar and Avondale
- Two 345 kV transmission circuits between Lamar and Burlington
- Two 345 kV transmission circuits between Burlington and Big Sandy
- One 345 kV transmission line between Big Sandy and Missile Site
- One 345 kV transmission line between Big Sandy and Story
- One 345 kV transmission line between Story and Pawnee
- A new Avondale Substation
- Two 230 kV transmission circuits between Lamar and Vilas

Since completion of the 2013 Lamar-Front Range studies, the eastern Colorado transmission system has materially changed with the addition of new resources and transmission facilities. The goal of the task force was to evaluate potential transmission alternatives to the Lamar-Front Range plan.

In April 2019, the LFRTF finalized a study scope and began evaluating transmission alternatives. The LFRTF performed technical analysis of 26 alternatives that facilitated the addition of new resources in eastern Colorado. Several other alternatives were considered, but not included in the technical analysis. The costs of the alternatives for this analysis were based on indicative (planning level) capital construction costs. The benefits of the alternatives were measured primarily in terms of how much incremental generation a particular alternative could accommodate compared to cost of the alternative. Other costs and benefits may be achieved, but were not the focus of this analysis. The LFRTF provided an open stakeholder forum to analyze the costs and benefits of alternative transmission proposals.

The LFRTF has held seven regularly scheduled meetings since February 2019 to discuss study assumptions, study methodology, potential alternatives, cost estimates, and benefits. The LFRTF Subcommittee participant list consisted of 38 stakeholders representing the following entities:

- Apex Clean Energy
- Black Hills
- Buckyball Systems
- Colorado Energy Office
- Colorado Springs Utilities
- Dietze and Davis, P.C.
- Juwi
- Independent Transmission Company
- Invenergy
- New Law Group
- Orion Renewable Energy Group
- Platte River Power Authority
- Savion Energy
- State of Colorado – Office of Consumer Counsel
- State of Colorado – Public Utilities Commission
- Tradewind Energy
- Tri-State Generation & Transmission
- Western Area Power Administration
- Xcel Energy

Meetings were held on:

- February 6, 2019
- March 7, 2019
- April 4, 2019

- June 6, 2019
- June 27, 2019
- July 30, 2019
- September 12, 2019

Prior to the March 2019 meeting, four stakeholders submitted transmission alternatives for consideration. The LFRTF addressed the stakeholder comments during the course of the study process, which was documented in meeting notes.

The LFRTF stakeholders evaluated numerous alternative proposals and agreed to perform technical analysis of the following 14 standalone alternatives:

1A. New 345 kV line from Burlington to Shortgrass to Big Sandy to Story to Pawnee Substation
1B. Alt 1A without Big Sandy Substation interconnection
2. New 345 kV line from Cheyenne Ridge to Burlington to Big Sandy to Missile Site Substation
3A. New 345 kV line from Missile Site to Cheyenne Ridge to Wray to Story to Pawnee Substation; Replace Burlington-Lamar 230 kV Project with New 345 kV line from Cheyenne Ridge to Lamar Substation; New 230 kV line from Cheyenne Ridge to Burlington Substation
3B. Alt 3A without Wray Substation interconnection
4A. New 345 kV line from Missile Site to Burlington to Wray to Story to Pawnee Substation; Replace Burlington-Lamar 230 kV Project with New 345 kV line from Burlington to Lamar Substation
4B. Alt 4A without Wray Substation interconnection
5. New 345 kV line from Lamar to Midway Substation
6. New 345 kV line from Lamar to Comanche Substation
7A. New 345 kV line from Badger Hills to Lamar to Boone Substation; Replace Burlington-Lamar 230 kV Project with New 345 kV line from Cheyenne Ridge to Lamar Substation; New 230 kV line from Cheyenne Ridge to

Burlington Substation; Sectionalize Comanche to Daniels Park 345 kV line #1 or # 2 at Badger Hills Substation

7B. Alt 7A without New 345 kV line from Lamar to Boone 345 kV

8A. New 345 kV line from Badger Hills to Lamar to Boone Substation; Sectionalize Comanche to Daniels Park 345 kV line #1 or # 2 at Badger Hills Substation

8B. Alt 8A without New 345 kV line from Lamar to Boone 345 kV

9. New 345 kV line from Badger Hills to Lamar to Boone Substation; Sectionalize Comanche to Daniels Park 345 kV line #1 or # 2 at Badger Hills Substation; New 345 kV line from Lamar to Cheyenne Ridge Substation

The LFRTF stakeholders evaluated the standalone alternative results and agreed to perform technical analysis of the following twelve combined alternatives:

Alt 3A + 5
Alt 3B + 5
Alt 3A + 7A
Alt 3A + 7B
Alt 3B + 7A
Alt 3B + 7B
Alt 4A + 5
Alt 4B + 5
Alt 4A + 7A
Alt 4A + 7B
Alt 4B + 7A
Alt 4B + 7B

Meetings to review and approve a draft study report are forthcoming. All supporting documentation including meeting agendas, presentations, and notes are accessible from the CCPG – Lamar Front Range Task Force website located at:

http://regplanning.westconnect.com/ccpg_lamar_tf.htm

Energy Storage and Non-wires Alternatives Working Group

As the Companies' strive to reduce carbon emissions, it is recognized that future challenges will require leveraging a portfolio of innovative technologies to support the Companies' goals of a cleaner and more reliable bulk electric system. As a part of this effort, Public Service has initiated and established the Energy Storage Work Group (ESWG) within the Colorado Coordinated Planning Group (CCPG). ESWG will analyze the performance and integration of such systems to identify benefits and challenges for energy storage and other non-wire alternative technologies. The ESWG will evaluate these technologies and develop recommendations for consideration of CCPG and stakeholders. Recommendations will focus on the integration of energy storage resources into the bulk electric system as well as non-wire alternative technologies to address capacity needs and reliability constraints as they relate to the bulk electric system. The ESWG aims to accomplish these goals by assembling resources from the various members of the CCPG as well as external subject matter experts as needed.

The ESWG held its first meeting on January 23, 2020. Several meetings will be scheduled through the remainder of the year as need.

VII. 10-Year Transmission Plan Compliance Requirements

A. Efficient Utilization on a Best-Cost Basis: Rule 3627(b)(I)

Each Company endeavors to conduct transmission planning with the goal of achieving best-cost solutions that balance numerous factors and result in optimal transmission projects. Rule 3627(b)(I) defines “best-cost” as “balancing cost, risk and uncertainty and includes proper consideration of societal and environmental concerns, operational and maintenance requirements, consistency with short-term and long-term planning opportunities, and initial construction cost."

The Companies recognize that a project that is financially impractical will experience difficulty in gaining support from the Commission, customers, shareholders in the case of Black Hills and Public Service, and members in the case of Tri-State. However, cost is not the only consideration when selecting and developing transmission projects. The Companies take a number of factors into consideration when planning the long-term build-out of the transmission system, including but not limited to the following:

- Load projections
- Project partnership opportunities
- Regional congestion
- Transportation corridors
- Transmission corridors
- City and county zoning
- Geographic features
- Societal and environmental impacts
- Operational and maintenance requirements
- Consistency with short-term and long-term planning opportunities
- Initial construction cost

The impact each factor has on a particular project varies based on the nature of the project. Nevertheless, each factor is considered to some extent during the planning stage.

Take the fairly broad environmental and societal concerns factor, for example. As its name implies, this factor considers how a project relates to the natural environment and the public in general – both positively and negatively. In the context of transmission planning, this usually means:

- The negative effects to the local environment from constructing a new transmission line or substation.
- The net positive impact to the environment of constructing a particular new transmission facility as an alternative to a different project over a more sensitive area.
- The positive impact to the environment of utilizing existing transmission corridors or upgrading existing facilities rather than constructing new ones.
- The positive impact to the environment and society if a project gives transmission customers access to a more diverse mix of generation resources, which can potentially reduce overall emissions and energy costs.
- The positive impacts to society by providing stable and reliable electricity. This is particularly important in rural areas where a single transmission outage has the potential to de-electrify entire regions.

For example, a planner may determine, by inspection, that a certain alternative is not practical because it would require a new transmission line over sensitive or exceptionally rugged terrain. This occurred in the CCPG San Luis Valley Subcommittee. The Subcommittee was tasked with evaluating the performance of alternatives to improve several deficiencies in the San Luis Valley transmission system, the biggest deficiency being that a single line outage can cause widespread outages to customers served by Public Service and Tri-State in Saguache, Mineral, Rio Grande, Alamosa, Costilla, and Conejos counties. One proposed alternative was to add a second 230 kV line to the

San Luis Valley from either Montrose or Pagosa Springs. Electrically speaking, a new transmission line from either of these sources would likely improve reliability in the San Luis Valley. However, the Subcommittee declined to analyze them in part because these alternatives would require the construction of new transmission lines across rugged mountainous regions. Given the potential costs, environmental impacts, and permitting and construction challenges, it was decided these alternatives did not justify the effort required to model and analyze them. More information on the work of the CCPG San Luis Valley Subcommittee can be found in the Colorado Coordinated Planning Group San Luis Valley Subcommittee report in Appendix M.

Operational and maintenance concerns also are considered in the planning process. These factors include things such as:

- Spare equipment strategies, particularly for equipment that if failed, would take longer than six months to replace.
- The ability of the system to allow maintenance outages of lines and transformers.
- The capability of the system to accommodate required and increased demands on limited transmission path transfer limits.
- The capacity of the system to allow generators to output their full energy without operating restrictions or operating procedures (congestion).
- Increasing system robustness so that the use of load shedding, special protection, and cross tripping schemes can be minimized.

For example, operational and maintenance concerns were considered by the CCPG Northeast Colorado Subcommittee in its 2017 Northern Greeley Area Transmission Plan System Impact Study Report. The study focused on improving the Greeley area 44kV transmission system, which is antiquated and operated in a mostly radial fashion. The Subcommittee proposed and evaluated several potential transmission projects to improve system reliability and maintenance of the transmission system in the Greeley area. More information on this study can be found in the Northern Greeley Area Transmission Plan System Impact Study Report included in Appendix N.

Good transmission planning requires that alternatives be evaluated in the context of short-term and long-term planning opportunities as well. In planning vernacular, this means considering:

- The relative ability of transmission alternatives to serve more loads, whether it is in the near-term or long-term planning horizon;
- The capability of new transmission alternatives to allow the injection and export of new generation resources; and
- The manner in which transmission alternatives align with longer-term transmission strategies.

The CCPG Northeast Colorado Subcommittee explicitly considered each of these factors in the 2017 Northern Greeley Area Transmission study. Voltage Stability ("P-V") analysis was performed for each studied alternative to compare its relative strength. This type of analysis is a common way to consider the relative ability of various transmission alternatives to serve future loads. The Northern Greeley Area Transmission Study considered the ability of each alternative to allow new resources out of the Greeley area and each alternative's ability to align with a longer-term area transmission plan known as the Southwest Weld Expansion Project located to the south of Greeley.

In general, a primary method of identifying and addressing many of the planning factors is through stakeholder participation in the planning process. Since planning is one of the initial stages of transmission project development, a preliminary evaluation of the aforementioned factors is typically performed as a screening process, with progressively more meaningful, in-depth evaluation occurring through the siting, permitting, and construction stages of development.

Adherence to best-cost principles is formally reflected by each Company in its internal policies. For example, Tri-State policy requires careful consideration of:

- Cost comparison of alternatives for providing capacity to serve load
- The use of existing delivery points and sub-transmission system
- Early construction of other delivery points planned by the member and/or neighboring utilities
- Alternate locations for the new delivery point
- Possible augmentation of the distribution system in lieu of transmission facility construction

The Companies perform an economic feasibility study of the best alternatives using the "single-entity concept," taking into consideration the total costs to the lead Company, as well as other affected utilities or member cooperatives. During the economic study, the following criteria are evaluated:

- Electrical performance of existing and proposed facilities, to include voltage drop, power flow, and losses
- Estimated capital and annual costs
- Wheeling costs
- Reliability
- Environmental considerations
- Coordination with other transmission providers' long-range transmission plans

In addition, the Companies incorporate "best cost" considerations through their interactions with various federal, state, and local regulatory bodies. Among other requirements, FERC has imposed planning requirements on utilities through its Order No. 890 and Order No. 1000, both of which include considerations consistent with Rule 3627's “best cost” approach. These FERC requirements are discussed further below.

All of the Companies participate in Commission dockets and initiatives, spending significant time and resources for Notices of Proposed Rulemaking, outreach efforts, meetings with Commission Staff and actively participating in initiatives in which the Commission has expressed interest. In addition, the Companies participate with Commission staff in the development of the conceptual long-range plans for Colorado's electric transmission infrastructure. The Companies individually meet with representatives of the Colorado Energy Office ("CEO") and take into consideration CEO's suggestions. The Companies also meet with local governmental officials. These meetings transcend simple permitting requests and consider factors such as the economic development aspirations of the communities, cultural concerns of communities, and the environmental aspects of transmission infrastructure expansion contemplated in various regions.

B. Reliability Criteria: Rule 3627(b)(II)

The Energy Policy Act of 2005 ("EPAct") amended the Federal Power Act ("FPA") to create mandatory electric reliability standards for the U.S. bulk power system. In compliance with these federal laws, FERC certified NERC as the electric reliability organization responsible for developing and enforcing the mandatory reliability standards authorized by the EPAct. NERC also utilizes delegation agreements with regional reliability organizations, such as WECC. Various mandatory reliability standards relating to bulk power system planning, operations, and maintenance have been implemented by NERC and WECC as a result of the EPAct with the potential for fines of up to $1 million per day for serious violations that could impact the integrity of the bulk power system.

The NERC Reliability Standards can be found at NERC's website.
www.nerc.com/pa/stand/Pages/default.aspx

The WECC TPL Standards can be found at WECC's website.
www.wecc.biz/Standards/Pages/Default.aspx

Each of the Companies take NERC and WECC compliance extremely seriously and stringently adhere to all applicable standards and criteria. Additional information concerning each Company's reliability compliance efforts is provided below.

1. *Black Hills Reliability Criteria*

On top of NERC and WECC requirements, the following additional guidelines are utilized in the planning process for determining acceptable levels of service for the Black Hills service territory:

- Transmission line loadings should not exceed 100 percent of continuous seasonal rating or the established equipment or operating limits.
- Transformer loading under system intact conditions should not exceed 100 percent of the normal rating.
- Transformer loading under contingency conditions should not exceed 100 percent of the emergency rating.
- Transmission bus voltage levels during normal conditions will be maintained between 0.95 p.u. and 1.05 p.u. of nominal system voltage.
- Transmission bus voltages during contingency conditions will be maintained between 0.90 p.u. and 1.1 p.u. of nominal system voltage.
- Following a disturbance, all machines in the system shall remain in synchronism as demonstrated by their relative rotor angles for all Category P1 contingencies.
- A generator that pulls out of synchronism in the simulation shall not result in the tripping of any additional transmission facilities.
- If a machines maximum relative rotor angle swing exceeds or equals 16 degrees any time two seconds after the fault has cleared, the damping shall be greater than 3% as defined by:

$$\%\,Damping = \frac{\ln\left[\dfrac{1st\ Cycle\ Peak - 1st\ Cycle\ Min}{Final\ Cycle\ Peak - Final\ Cycle\ Min}\right]}{Cycle\ Count * 2\pi} * 100$$

- For events where the maximum machine relative rotor angle swings are within a 16 degree window are assumed adequately damped

Additional details on the reliability criteria observed by Black Hills are provided on pages 15-18 of the Black Hills Open Access Transmission Tariff ("OATT") Attachment K Methodology, Criteria, and Process Business Practices document, available in Appendix L.

2. *Tri-State Reliability Criteria*

In addition to complying with NERC and WECC standards and criteria, Tri-State observes its own set of internal criteria for planning studies. Tri-State performs an annual assessment of its regional interconnected transmission system elements utilizing simulation modeling cases created by WECC members. This annual assessment takes into account Tri-State's members in four states, with associated projects located in Colorado included in this plan.

The modeling cases selected represent projected loads and transmission system topology for the year one through five horizon and the year six through ten horizon. These cases are selected to demonstrate system performance covering a range of forecasted demand levels and the most critical system conditions and study years. This analysis examines heavy and light loading scenarios, typically in cases modeling year one, year five, and year ten, unless other factors, such as known major system changes, dictate selection of another year. Cases created by WECC ensure that all projected firm transfers and established normal (pre-contingency) operating procedures are modeled, as well as existing and planned reactive power resources.

The transmission system is analyzed considering the planned projects for each utility in the study area. This assessment includes one or more current or past studies, which together address the entire Tri-State area of service.

Additional information concerning Tri-State's reliability criteria is available in its Engineering Standards Bulletin and is updated periodically. The most current version at the time of this filing can be found in Appendix M.

3. *Public Service Reliability Criteria*

In addition to fulfilling NERC and WECC standards and criteria, Public Service observes internal company criteria for planning studies. The most recent internal criteria can be found in Appendix N.

C. Legal and Regulatory Requirements: Rule 3627(b)(III)

Per Rule 3627(b)(III), “Each ten year transmission plan shall demonstrate compliance with…[a]ll legal and regulatory requirements, including renewable energy portfolio standards and resource adequacy requirements.” The following sections provide information concerning each Company's compliance with such legal and regulatory requirements.

1. Black Hills Legal Requirements

Black Hills’ portion of the 2020 Plan complies with all applicable NERC and WECC reliability standards, as well as other applicable legal and regulatory requirements, including the Colorado RES. For information on resource planning, for both resource adequacy and RES statutory compliance, please refer to the most current Proceeding 16A-0436E as follows:

Proceeding No. 16A-0436E

- Resource Planning, ERP - Phase I 2016 and Phase II 2017

  Black Hills' 2016 ERP was docketed at the Colorado Public Utilities Commission in Proceeding No. 16A-0436E. The Company's ERP application was filed on June 3, 2016, pursuant to Commission rules and the RES codified at C.R.S. § 40-24-124.

  The ERP covered a Planning Period of 25 years from January 2016 through December 2040, and a Resource Acquisition Period of seven years from January 2016 through December 2022. The Planning Period pertains to ERP Phase I, a Commission determination of resource need. The Resource Acquisition Period pertains to ERP Phase II, a competitive solicitation for resource acquisition.

  On January 17, 2017, Recommended Decision No. R17-0039 was entered for Phase I and became a decision of the Commission by operation of law. The decision adopted a settlement agreement filed on November 10, 2016. The settlement agreement modified certain terms of the Company's ERP application. Specifically, the settlement agreement approved, in pertinent part, a resource need of up to 60 MW from RES-eligible energy resources for commercial operation in 2019. The 60 MW will enable the Company to comply with the 30% RES requirement in 2020. Standalone REC bids, to fulfill the 60 MW resource need, were not allowed under the settlement agreement. The settlement agreement approved evaluation criteria for utility-owned resource bids. Finally, the settlement agreement stipulated a timeline for Phase II to ensure that federal production tax credits can be advantaged for eligible bids.

  A Phase II competitive solicitation for 60 MW of eligible energy resources was conducted by the company on June 23, 2017. The Company received over 100 individual bids from multiple project developers for eligible energy resources from wind, solar PV, and other resources. An independent evaluator was retained (Accion Group) to observe the Company's bid solicitation and evaluation process, and report findings. Based on the evaluation process, Bid 1117-1 was ranked the highest overall, including both economic and noneconomic evaluation criteria. Economic criteria identified Bid 1117-1 with the lowest NPVRR and the most avoided cost savings of all the bids offered in the Company's solicitation.

Bid 1117-1 is a PPA for 60 MW supplied by a wind facility located in Huerfano and Las Animas counties. The output of approximately 201,500 MWh of energy and renewable energy credits annually will enable the Company to comply with the 30% RES beginning in 2020. The awarded Bid 1117-1 will be online for commercial operation no later than December 31, 2019.

- <u>RES Compliance Plan, 2018-2021</u>

  The settlement agreement in ERP Proceeding No. 16A-0436E approved acquisition of on-site solar photovoltaic ("PV") and community solar garden ("CSG") resources for RES compliance.

  The PV capacity is established at 1,500 kW per year for the compliance period, 2018-2021. The settlement agreement stipulated categories for PV system sizes and incentive levels.

  The CSG program was defined in the settlement agreement to be comprised of two RFP offerings by the Company based on the type of subscribers. Each year, the Company will solicit and award up to 500 kW of CSGs for 100% low-income subscribers and up to 2,000 kW of CSGs for open subscribers. The settlement agreement stipulated 0 kW as the minimum purchase amount and 2,500 kW as the maximum purchase amount from CSG installations each compliance year, 2018-2021. The Company expects that 15.12 MW of CSGs will operate by end of 2021.

2. Tri-State Legal Requirements

Tri-State's 2020 Plan complies with all applicable NERC and WECC reliability standards, as well as other applicable legal and regulatory requirements including Company and member compliance with the Colorado RES.

For the period 2015 through 2019, the Colorado RES requires that 6 percent of Tri-State's Member Systems' retail energy sales be served by renewable generation, growing to 20 percent in 2020 and beyond. In addition, as a qualifying wholesale utility, the Colorado RES requires Tri-State to generate or cause to be generated at least 20 percent of the energy it provides to its Colorado Member Systems at wholesale from eligible energy resources in the year 2020 and thereafter. As the wholesale power provider for its Member Systems, Tri-State's 2020 Plan is developed to ensure that the necessary transmission system capabilities will be in place to meet both its Colorado Members Systems' and its own RES requirements.

For additional information on resource adequacy requirements and resource requirements to meet the RES, please refer to Tri-State's Integrated Resource Plan/Electric Resource Plan and Electric Resource Plan Annual Progress Reports available in Appendix M.

As discussed previously, Tri-State may be subject to federal and state regulations related to carbon emission reductions from existing power plants, such as the regulations that will be promulgated pursuant to Colorado HB 19-1261. While no such regulations have been promulgated as of the date of this 10-Year Plan, Tri-State anticipates that such regulations may be promulgated within the next two years and, if so, will address them in the next 10-Year Transmission Plan. Tri-State also notes that, since it operates an interconnected, interstate transmission system, its transmission system may be impacted as a result of federal compliance and carbon emission reduction plans enacted in other states in which Tri-State operates.

3. Public Service Legal Requirements

Public Service's 2020 Plan complies with its currently operative ERP, approved by the Commission in Proceeding 16A-0396E in its Phase II decision, C18-0761. Additional information on Public Service resource adequacy and compliance with Commission rules related to ERPs is available at:
https://www.xcelenergy.com/company/rates_and_regulations/resource_plans

Public Service's 2020 Plan additionally complies with its currently operative RES Compliance Plan approved by the Commission as modified by settlement in Decision C16-1075 in Proceeding 16A-0139E. [5] Public Service's 2020 Plan also complies with the specifications set forth in its 2020-2021 RES Compliance Plan, filed in Proceeding 19A-0369E, and currently under Commission consideration.

Information on Public Service compliance with RES requirements is available at:
https://www.xcelenergy.com/company/rates_and_regulations/filings

D. Opportunities for Meaningful Participation: FERC Order No. 890

In addition to the CCPG planning processes, each of the Companies has its own FERC Order No. 890 stakeholder process as described below. For additional information on stakeholder involvement pertinent to Rule 3627, please refer to Section VI.

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[5] Public Service's 2017-2019 RES Compliance Plan was subsequently extended through the first quarter of 2020 by Decision R19-0807 in Proceeding No. 19A-0369E.

1. *Black Hills Participation Strategy*

For Black Hills, the FERC Order No. 890 Stakeholder Process is included in its Attachment K to its Open Access Transmission Tariff ("OATT"), which is included in Appendix L of this document. Additional information concerning Black Hills' FERC Order No. 890 processes can also be found in Appendix L.

2. *Tri-State Participation Strategy*

Attachment K to Tri-State's OATT demonstrates Tri-State's transmission planning processes consistency with FERC Order No. 890 planning principles. As discussed previously in this 2020 Plan, all projects included herein have been identified and developed through Tri-State's transmission planning process.

Attachment K to Tri-State's OATT can be updated periodically, and is available on Tri-State's OASIS at:
http://www.oasis.oati.com/tsgt/index.html

The most current version at the time of Attachment K is located in Appendix M.

3. *Public Service Participation Strategy*

For Public Service, the FERC Order No. 890 stakeholder process is included in the Xcel Energy Joint OATT Attachment R, available at the following website:
https://www.oasis.oati.com/woa/docs/PSCO/PSCOdocs/PSCo_Attachment_R_5-5-2020.pdf
Additional information concerning the Public Service FERC Order No. 890 processes can be found at:
http://www.oatioasis.com/psco/index.html under "FERC 890 Postings".

E. Coordination Among Transmission Providers: FERC Order No. 1000

In July 2011, FERC issued a final rule related to transmission planning and cost allocation, FERC *Order 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities* ("Order 1000"). This order builds on planning principles already established in FERC Order No. 890, as previously discussed. FERC Order No. 1000 requires that transmission owning and operating public utilities:

1) Participate in a regional transmission planning process that produces a regional transmission plan.
2) Amend their OATT to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes.
3) Remove from Commission-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities.
4) Improve coordination between neighboring transmission planning regions for interregional transmission facilities.
5) Participate in a regional transmission planning process that has a regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation.
6) Participate in a regional transmission planning process that has an interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions.

WestConnect is one of four planning "regions"[6] within WECC established for regional transmission planning to comply with Order 1000. Public Service and Black Hills have designated WestConnect as their Order 1000 compliant planning regions. Tri-State has joined WestConnect as a coordinating transmission owner, which means it is not subject to all of the requirements under Order 1000 such as accepting binding cost allocation for regional transmission projects. The WestConnect planning process is described in Black Hills' and Public Service's OATTs (Attachment K and R respectively; links are provided above) as well in documentation found on the WestConnect website (http://www.westconnect.com/). The WestConnect website also houses information and announcements for many public planning meetings. WestConnect accepts stakeholder input throughout the planning process.

WestConnect develops a regionally coordinated transmission plan that begins with the determination of regional reliability, economic and public policy needs. The more cost-effective or efficient solutions to meet identified regional needs are included in the regional plan. These regional projects may be new projects in addition to the projects developed through the local or sub-regional planning processes or may replace local projects in some instances. If WestConnect determines Colorado utilities benefit from a regional project, then those Colorado utilities may be responsible for a portion of the cost of the regional project.

Additionally, WestConnect coordinates with the other western Order 1000 planning regions. This coordination also is described in Black Hills' and Public Service's planning attachments to their respective OATTs.

[6] The other three are Columbia Grid, Northern Tier Transmission Group, and the California Independent System Operator.

VIII. 10-Year Transmission Plan Supporting Documentation

A. Methodology, Criteria, & Assumptions

1. *Facility Ratings (FAC-008-3)*

NERC Reliability Standard FAC-008-3 requires that transmission and generation owners document the methodology used to develop ratings of their equipment. The standard requires that the transmission or generation owner supply its methodology to specific NERC registered entities upon request. FAC-008-3 also requires transmission and generation owners to establish facility ratings per the methodology established through FAC-008-3. Each transmission and generation owner has documented ratings for each of its facilities. The standard requires the transmission or generation owner to supply its facility ratings to specific NERC registered entities (i.e. associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s)) upon request. These documents are not publicly available and are not required to be per NERC standards. NERC Reliability Standard MOD-032-1 requires applicable entities to provide equipment characteristics, including established facility ratings, to NERC and WECC according to established reporting requirements. This is accomplished through the WECC Base Case Compilation Schedule as prescribed by the Data Preparation Procedural Manual.

a. Black Hills Ratings

Documentation of Black Hills' FAC-008-3 methodology is available in Appendix L.

b. Tri-State Ratings

Documentation of Tri-State's Facility Rating's methodology is available in its Engineering Standards Bulletin. The most current version of Tri-State's

Engineering Standard’s Bulletin at the time of this filing can be found in Appendix M.

c. Public Service Ratings

Documentation of Public Service FAC-008-003 methodology can be found in Appendix N.

2. *Transmission Base Case Data: Power Flow, Stability, Short Circuit*

The Companies utilize transmission system power flow and transient dynamics modeling data prepared by WECC. Through its Annual Study Program, WECC facilitates the preparation of at least 10 models per year. The models represent a variety of system conditions out to a 10-Year planning horizon. WECC's 10-Year Regional Transmission Plan is an Interconnection-wide perspective on: 1.) expected future transmission and generation in the Western Interconnection, 2.) what transmission capacity may be needed under a variety of futures, and 3.) other related insights.

WECC members participate in the data preparation process for the models and Public Service coordinates the data for the Rocky Mountain region. Prior to being used for planning studies, the models are reviewed and adjusted to reflect the most current and accurate system elements, ratings, and operating conditions for the region to be studied. Short circuit data is coordinated between neighboring TPs as needed and periodically coordinated at the CCPG level.

Instructions for obtaining access to WECC base cases are as follows:

a. An organization requesting WECC base case(s) must either be a WECC member or they must execute the “Nonmember Confidentiality Agreement for WECC Data.”

b. Non-members may obtain the confidentiality agreement from WECC by requesting the agreement from a WECC Stakeholder Services representative.

The submission must include a statement from the organization explaining why they have a legitimate business need for the WECC base case(s).

B. Load Modeling

Pursuant to each Company's OATT, network customers are required to submit 10-Year projected network loads and network resources by October 1 of each year. This information is then compiled with existing data and information to provide a basis for identification of the minimum transmission system enhancements required to ensure that a sufficiently robust transmission system is in place to meet all network customer requirements under all scenarios.

1. *Forecasts*

The Companies rely on the most recent and accurate load forecasts when developing system planning models. General load forecast assumptions are posted on each transmission provider's Company or OASIS site.

a. Black Hills Forecasts

In 2016, Black Hills filed with the Commission its latest ERP, which included details on expected customer growth based on load forecast information submitted annually by network customers. The ERP, in conjunction with the network customer forecast updates, is used in the development of Load and Resource ("L&R") reports submitted to WECC on an annual basis. Once the L&R report is developed, this forecast is disaggregated to the respective transmission system load buses. There are two types of load buses: (1) a load bus where the load does not change over time (e.g. a single large industrial load bus); and (2) a load bus where the load changes over time (e.g. a residential load). Black Hills uses its knowledge of load characteristics along with historical loading observations to estimate the individual load bus data in time. The load bus forecasts are summed and compared to the WECC L&R report aggregate load forecast. If the two forecasts do not match, the variable bus load forecasts are adjusted until the two forecasts match. Through this procedure, the WECC L&R reports, including the assumptions in the latest ERP, are reflected in the transmission planning models used within the WECC footprint. Deviations from the ERP load forecast are commonplace in transmission studies depending on the purpose of the planning analysis being performed and the study scenario of interest. The load assumptions included in the planning model are typically specified within each planning study report for reference.

Details related to Black Hills' load forecast can be found in Black Hills' 2016 ERP in Colo. Consolidated Proceeding No. 16A-0436E; specifically, Attachment LS-1 included in Appendix L of this report.

b. Tri-State Forecasts

General load forecast information is available on Tri-State's OASIS at:
http://www.oasis.oati.com/tsgt/index.html
The Load Forecast Descriptive Statement available at the time of this filing is located in Appendix M.

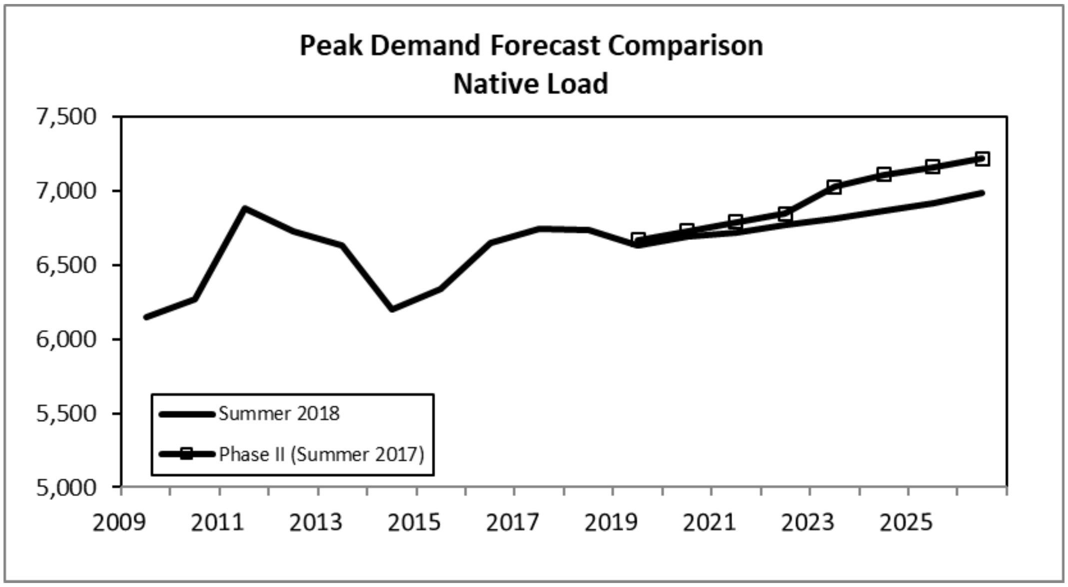
Tri-State prepares load forecasts on a system-wide and regional basis with regional forecasts used for resource planning purposes. Tri-State receives load forecasts from its network customers by October 1 of each year. These loads are modeled as required for inclusion in the planning models developed in conjunction with neighboring entities.

Tri-State's most recent transmission plans utilize 2018 load forecast data. Base forecast data for these plans is available in Appendix A of Tri-State's ERP/APR, located in Appendix M.

c. Public Service Forecasts

The load forecast used in this filing is the Summer 2018 PSCo Load Forecast, which was provided publicly in the Company's 2016 Electric Resource Plan Annual Progress Report filed dated October 31, 2018 (Proceeding No. 16A-0396E) and the PSCo Load Forecast that was provided publicly in the Company's 2016 Electric Resource Plan Modeling Assumptions Update filed in August 2017. The following figure shows a comparison between the two forecasts. The drivers of the changes in the forecast are discussed in Appendix N. The Company notes that while it has developed more recent load forecasts (e.g., as provided in the Company's 2016 Electric Resource Plan Annual Progress Report dated October 2019 filed in Proceeding No. 16A-0396E and in Proceeding No. 19A-0409E), the Summer 2018 forecast was the most current publicly available forecast at the time the Company began the analysis and preparation of this Rule 3627 Report.

Figure 8. Public Service Historic and Forecast Demand



In addition to native load forecasts, Public Service receives forecasts from its wholesale customers, which it incorporates into the overall forecast. Transmission planners allocate the loads on a substation-by-substation basis, based on historical trends. Additional information is included in Appendix N.

2. *Demand-Side Management*

The effects of Demand-Side Management ("DSM") program savings are typically taken into account within the load forecasts described previously. Within the context of power system modeling, DSM is simply reflected in the power flow model as reduced load and therefore included in planning studies.

a. Black Hills DSM

Details related to the effects of DSM savings estimates on Black Hills' load forecast can be found in the 2016 Black Hills ERP; specifically, Attachment LS-1, which is included in Appendix L of this document.

b. Tri-State DSM

Load forecasts provided for bulk electric transmission planning typically include existing DSM and other load-reducing programs, including member energy efficiency programs and local distributed generation. These programs are reflected in the power flow model as reduced load and are inherently included in studies. For transmission planning, load forecasts that contain load-reducing factors may be used for specific projects or for individual Tri-State members with DSM, local distributed generation, or other energy efficiency programs. For such cases, please refer to individual project planning studies. For Tri-State's system load forecast, these are described in Tri-State's 2018 Annual Progress Report to the 2015 ERP found at:
https://www.tristategt.org/resource-planning

c. Public Service DSM

Public Service accounts for DSM through reduction in its load forecast based, in part, on the goals established by the Commission. Additional information is included in Appendix N.

C. Generation and Dispatch Assumptions

Generator and associated equipment models are typically included in the WECC Annual Base Case Compilation Schedule base cases as required by the Data Preparation Manual. The detail of generation models utilized within planning studies can vary depending on the nature of the study. For example, a Large Generator Interconnection study for a wind facility may explicitly model each individual wind turbine and the associated collector system to properly assess the low voltage ride through capabilities of the facility. That same facility may be modeled as a single equivalent wind turbine with an equivalence collector system within a long-range planning study where the performance of individual wind turbines is not a concern. The scope of the technical study will influence the level of detail that is modeled.

1. *Black Hills Assumptions*

At the most basic level, Black Hills dispatches existing generation to meet the demand requirements of its system, including load and losses. The objective of a particular study often drives the individual generator dispatch levels. For example, a peak demand summer baseline scenario may consist of a majority of dispatchable baseload generation online and an appropriate mix of wind and solar PV to meet the demand requirements. An off-peak demand spring or fall scenario may have the available wind generation dispatched at its nameplate capacity with the dispatchable baseload generation and solar generation reduced to capture the impacts of that particular dispatch pattern. Existing power purchase agreements and other contractual arrangements may be reflected in certain study scenarios to further stress the transmission system. Black Hills also may include speculative generation (as identified in the current version of the Black Hills Colorado Electric Generation Interconnection Request Queue, included in Appendix L) in certain transmission studies as dictated by the study objective. Additionally, existing and/or conceptual generation may be dispatched beyond the demand requirements of the study case to facilitate a net export of energy from the study area. A listing of existing and planned resources utilized in planning studies is typically included in each specific study report.

2. *Tri-State Assumptions*

Tri-State's transmission planning function receives generation assumptions from its network customers--Tri-State Power Management, Arkansas River Power Authority (“ARPA”), Municipal Electric Agency of Nebraska (“MEAN”), Raton Public Service Company (“City of Raton”), Public Service Company of Colorado (“PSCO”), Kit Carson Electric Cooperative (“KCEC”) and Public Service Company of New Mexico

("PNM")--annually by October 1. These generation assumptions are utilized to ensure a sufficiently robust transmission system to meet network customers' needs over a 10-Year planning horizon.

Generation assumptions, including dispatch assumptions, and corresponding data for other transmission plans are project-specific. Therefore, the individual transmission studies should be referenced for generation assumptions relative to each such project.

3. Public Service Assumptions

Public Service transmission planning models reflect generation dispatch based on internal procedures that take into account production costs, maintenance schedules, and other factors. Procedures include:

- Modeling of generator planned outages with outage period of 6 months or more
- In general, if not needed to meet load requirements, high production cost generation plants are modeled out of service. If resources are needed, these units may be modeled
- Public Service combustion turbine generators are typically modeled at or near full output
- Public Service large coal-fired plants are typically modeled at or near full output. These units are considered "base loaded", in that they usually operate around the clock if generation adjustments are necessary, these generators are generally adjusted last
- Hydro generation has net dependable seasonal ratings. Each seasonal rating reflects the average generation that can be continuously maintained over the duration of the daily peak period for the respective season. In winter, the daily period is approximately five hours long. All generators on-line should be

producing reactive power ("MVARs"). Generator bus voltage scheduling may be necessary if the generating unit is acting in a condensing mode (consuming MVARs)

- Pumped Hydro generators are modeled appropriately in pumping mode during off peak hours.

Renewable generation, including wind and solar are modeled based on Public Service Variable Energy Resource Dispatch Assumptions. System changes, load transfers, and other topology changes also are coordinated through CCPG.

D. Methodologies

1. *System Operating Limits (FAC-010)*

System Operating Limits ("SOL") is defined in NERC Reliability Standard FAC-010-3 as the responsibility of the Planning Authority ("PA") to ensure reliable planning of the Bulk Electric System. SOL is required to be established per FERC standards but is not required to be publicly available.

a. Black Hills SOL

Black Hills has defined both Operational Criteria, which are limits for typical every day/normal operations, and SOLs, which are limits that are of an emergency nature and must be acted upon promptly to ensure facility ratings are not exceeded. Black Hills' SOLs are communicated to the Southwest Power Pool ("SPP") Reliability Coordinator so that when an SOL is exceeded, the Reliability Coordinator will be aware of the concern and be able to provide assistance in ensuring the SOL violation is removed. Black Hills' SOLs are summarized below:

- BES Transmission Line SOLs are exceeded when the line rating is exceeded.

- BES Voltage SOLs are exceeded when the Emergency Voltage rating is exceeded. The Emergency Voltage is plus/minus 10% of the nominal voltage.
- BES transformer SOLs are exceeded when their loaded MVA is between 100% and 125% of the established FOA Rating for more than 30 minutes, OR, their loaded MVA exceeds 125% of the established FOA Rating for any period of time.

b. Tri-State SOL

Tri-State is not a PA and, therefore, uses the SOL methodology as defined by the applicable PA.

c. Public Service SOL

Public Service has one SOL for the TOT7, which is located north of the Denver metro area. SOLs are required to be established per FERC standards, but are not required to be publicly available. The TOT7 studies are conducted annually. The results of those studies are available upon request.

2. *Available Transmission System Capability Methodology (MOD-001)*

Available Transmission System Capability Methodology is available and posted per NERC Standard MOD-001 at NERC's website.

a. Black Hills TTC

Black Hills utilizes the Rated System Path Methodology for determining Total Transfer Capability ("TTC") and Available Transfer Capability ("ATC") for all Posted Paths and in all ATC time horizons. The determination of TTC is based on the maximum flow of a path while meeting all reliability criteria for single initiating event outages. In the event that the path is flow-limited and a reliability limit cannot be reached, the transfer capability of the path is set to the thermal rating of the path. For further details on the calculation of transfer capability, refer to Black Hills' ATC Implementation Document ("ATCID") included in Appendix L.

b. Tri-State TTC

Tri-State's TTC path values for jointly owned paths that are interfaces identified and rated through WECC processes and OTC determinations are based upon the Rated System Path Methodology (NERC MOD-29-2a). Tri-State has TTC allocations on WECC rated Paths 30 (TOT1A), 31 (TOT2A), 36 (TOT3), 39 (TOT5), 47 (SNMI), and 48 (NNMI). These paths are studied by the path operator with actual flow levels at the combined path ratings under simulated N-1 scenarios to ensure that the planning reliability criteria are being met. The path participants have previously used studies and negotiations to determine the manner in which the TTC will be allocated to each of the participants.

For jointly owned paths that are not WECC-rated paths, the TPs determine the appropriate combined TTC and the allocation of it is based upon contractual capacity entitlements. This allocation is done outside of any WECC approval process since these are Tri-State TTC/ATCID minor paths that are not part of an interface and do not impact any major recognized WECC paths.

Tri-State utilizes TTC values based upon thermal facility ratings for all flow-limited paths that are owned solely by Tri-State. If the NERC MOD-029-2a requirement R2.1 simulation studies result in sufficient flow ability on a path segment to determine a reliability limit, then the TTC on the ATC path segment is set to the simulated flow corresponding to the reliability limit while at the same time satisfying all planning criteria.

In addition, Tri-State has created many extended ATC paths that are defined by a serial concatenation of rated path segments. The resulting TTC and ATC for each extended ATC path is based upon the lowest TTC and ATC of all the serial path segments included in each path definition.

The ATCID provides for the documentation of required information as specified in the NERC MOD Standards and the NAESB OASIS Standards regarding the calculation methodology and information sharing of ATC specific to this TP. The ATCID for Tri-State is available on Tri-State's OASIS at: http://www.oasis.oati.com/tsgt/index.html

The ATCID can be updated periodically and the most recent version of the ATCID at the time of this filing can be found in Appendix M.

c. Public Service TTC

The ATCID (MOD-001) for Public Service is available on Public Service's OASIS, by clicking on "ATC Information" and then "ATCID Implementation Document".

The ATCID can be updated periodically, and the most recent version at the time of this filing can be found in Appendix N.

3. *Capacity Benefit Margin (MOD-004)*

Capacity Benefit Margin ("CBM") methodology is available and posted per NERC Standard MOD-004.

a. Black Hills Capacity Benefit Margin (MOD-004)

Black Hills does not implement CBM in the assessment of ATC. The Capacity Benefit Margin Implementation Document ("CBMID") for Black Hills is included in Appendix L.

b. Tri-State CBM

Based on FERC's allowance for TPs to not use CBM, Tri-State does not allow for the use of CBM and, as such, its value is set to zero (0) in the ATC equations for all paths posted by Tri-State. Furthermore, Tri-State's practice is to not maintain CBM. Tri-State will review its CBM practice, at least annually, and will post any changes to the OASIS as needed. The CBMID for Tri-State is available on Tri-State's OASIS, by clicking on "ATC Information" and then "Capacity Benefit Margin Statement (CBMID)".

The CBMID can be updated periodically, and the most recent version at the time of this filing can be found in Appendix M.

c. Public Service CBM

The CBMID for Public Service is available on Public Service's OASIS, by clicking on "ATC Information" and then "CBM Implementation Document (CBMID)".

The CBMID can be updated periodically, and the most recent version at the time of this filing can be found in Appendix N.

4. *Transmission Reliability Margin Calculation Methodology (MOD-008)*

NERC Standard MOD-008-1, Transmission Reliability Margin Calculation Methodology, requires that each Transmission Operator prepare and keep current a Transmission Reliability Margin Implementation Document ("TRMID").

a. Black Hills Transmission Reliability Margin (MOD-008)

A copy of the current TRMID for Black Hills is located in Appendix L.

b. Tri-State TRM

The TRMID for Tri-State is available on Tri-State's OASIS at:
http://www.oasis.oati.com/tsgt/index.html

The TRMID can be updated periodically, and the most recent version at the time of this filing is located in Appendix M.

c. Public Service TRM

The TRMID for Public Service is available on Public Service's OASIS, by clicking on "ATC Information" and then "TRM Implementation Document (TRMID)".

The TRMID can be updated periodically and the most recent version at the time of this filing is located in Appendix N.

E. Status of Upgrades

Projects that constitute upgrades to existing transmission facilities are discussed in Section III of this Plan and the associated appendices.

F. Studies and Reports

Most of the Companies' study documentation can be found by starting at the sections of the WestConnect website that are dedicated to the CCPG:

http://www.westconnect.com/planning_ccpg.php
Additional Company-specific study and reporting resources are described below.

1. Black Hills Reporting

Public access to transmission market information, generator interconnection and transmission service requests, business practices, planning study reports and other topics related to the Black Hills transmission system is provided on Black Hills' OASIS at:
http://www.oatioasis.com/bhct

2. Tri-State Reporting

Planning studies and related reports for Tri-State transmission projects in Colorado are located at Tri-State's website at:
http://www.tristategt.org/transmission-projects
Generator interconnection, transmission service request, and other OATT study reports related to Tri-State's transmission system are provided on Tri-State's OASIS at:
http://www.oasis.oati.com/tsgt/index.html

3. Public Service Reporting

Planning studies and related reports for Public Service transmission projects in Colorado are located at the following links:

https://www.rmao.com/public/wtpp/PSCO_Studies.html
http://www.oatioasis.com/psco/index.html
http://www.transmission.xcelenergy.com/Planning/Planning-for-Public-Service-Company-of-Colorado

G. In-Service Dates

Information concerning the expected in-service date for each utility's facilities identified in the 2020 Plan and the entities responsible for constructing and financing each facility is contained in Table 1, Section III and Appendices A-I.

H. Economic Studies

The purpose of economic planning studies is to identify significant and recurring congestion on the transmission system and/or address the integration of new resources and/or loads. Such studies may analyze any or all of the following: (i) the location and magnitude of the congestion, (ii) possible remedies for the elimination of the congestion, (iii) the associated costs of congestion, (iv) the costs associated with relieving congestion through system enhancements (or other means), and, as appropriate (v) the economic impacts of integrating new resources and/or loads. Economic studies are generally described as being either “local” or “regional” in nature.

1. *Black Hills Economic Study Policies*

Black Hills conducts economic planning studies through the procedures outlined in its OATT Attachment K, which is included in Appendix L.

Black Hills will accept requests for economic studies on an annual basis. Information on making a request is available in the Attachment K Economic Study Request Form, as shown in Appendix L. Upon receiving a valid request for an economic study, Black Hills, with input from its stakeholder committee, will classify the request as local, subregional or regional. Black Hills will engage the appropriate resources to study up to one economic study request that has been classified as local on a biannual basis. All economic study requests that have been classified as subregional or regional will be forwarded to the WECC for inclusion in the appropriate study program. Since the 2018 Rule 3627 filing, Black Hills has not received any economic study requests, nor has it performed any economic studies.

2. *Tri-State Economic Study Policies*

Western Interconnection-wide congestion and economic planning studies are conducted by WECC in an open stakeholder process that holds region-wide stakeholder meetings on a regular basis. The WECC planning process is posted on its website (see http://www.wecc.org/Pages/home.aspx). Tri-State participates in the regional planning processes, as appropriate, to ensure data and assumptions are coordinated. Tri-State did not perform any economic studies this cycle nor were any requested by Tri-State stakeholders.

3. *Public Service Economic Study Policies*

Public Service facilitates priority local economic planning studies for its transmission system, pursuant to the procedures in its OATT Attachment R. Regional economic planning studies shall be performed by WECC, pursuant to procedures posted on the WECC website. Public Service did not perform any economic studies this cycle nor were any requested by stakeholders.

2020 CPUC Rule 3627 Appendices

TRI-STATE Generation and Transmission Association, Inc.   Xcel Energy®   Black Hills Energy Improving life with energy

SUPPLEMENTAL JOINT REPORT

For the State of Colorado

To comply with

Rule 3627

of the

Colorado Public Utilities Commission

Rules Regulating Electric Utilities

June 8, 2020

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ACRONYMS AND ABBREVIATIONS

Acronym or Abbreviation	Term
AQCC	Air Quality Control Commission
BA	Balancing Authority
Basin Electric	Basin Electric Power Cooperative
BESS	Battery Energy Storage Systems
Black Hills	Black Hills Colorado Electric, LLC, d/b/a Black Hills Energy
CAISO	California Independent System Operator
CAISO WEIM	California Independent System Operator Western Energy Imbalance Market
CCPG	Colorado Coordinated Planning Group
CDPHE	Colorado Department of Public Health and Environment
CEII	Critical Energy Infrastructure Information
Commission or CPUC	Colorado Public Utilities Commission
Companies	Black Hills, Tri-State and Public Service
Company	Black Hills, Tri-State or Public Service
CRI	Community Resiliency Initiative
CSU	Colorado Springs Utilities
DER	Distributed Energy Resources
DG	Distributed Generation
EIA	Energy Information Administration
ERP	Electric Resource Plan
ERZ	Energy Resource Zone
EV	Electric Vehicle
FACTS	Flexible AC Transmission System
FERC	Federal Energy Regulatory Commission
HTLS	High-Temperature Low-Sag
JDA	Joint Dispatch Agreement
Joint Utilities	Public Service Company of Colorado, Black Hills Colorado Electric, LLC, and Tri-State Generation and Transmission Association, Inc.
kV	Kilovolt
LDC	Local Distribution Company
LMP	Local Marginal Pricing
Member Systems	Member Cooperatives and Public Power Districts
MW	Megawatts
MWTG	Mountain West Transmission Group

Acronym or Abbreviation	**Term**
NERC	North American Electric Reliability Corporation
OATT	Open Access Transmission Tariff
Order 1000	FERC Order No. 1000 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities
PRPA	Platte River Power Authority
Public Service	Public Service Company of Colorado
PV	Photovoltaic
REP	Responsible Energy Plan
RES	Renewable Energy Standard
RTO	Regional Transmission Organization
SB07-100	Colorado Senate Bill 07-100
SCED	Security Constrained Economic Dispatch
SPP	Southwest Power Pool
TEP	Transportation Electrification Plan
TP	Transmission Provider
TPL	Transmission Planning
Tri-State or TSGT	Tri-State Generation and Transmission Association, Inc.
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
Western/WAPA	Western Area Power Administration (also WAPA)

I. Introduction

On February 3, 2020, Public Service Company of Colorado ("Public Service"), Black Hills Colorado Electric, LLC ("Black Hills"), and Tri-State Generation and Transmission Association, Inc. ("Tri-State" or "TSGT") (collectively referred to as the "Joint Utilities") jointly filed their biennial transmission plan (Joint Rule 3627 Transmission Plan), including a 10-Year Transmission Plan and 20-Year Conceptual Scenario Report in Proceeding No. 20M-0008E, as required by Rules 3625 to 3627 of the Colorado Public Utilities Commission ("Commission") Rules Regarding Electric Utilities (4 C.C.R. 723-3).

On April 1, 2020, the Commissioners deliberated on the Joint Rule 3627 Transmission Plan, and, pursuant to Decision No. C20-0213-I, directed the Joint Utilities to supplement their 10-Year Transmission Plan and 20-Year Conceptual Scenario Report with additional information, to be filed no later than June 8, 2020.

More specifically, the Commission directed the Joint Utilities to submit supplemental information in the following six general areas:

1) Clarification and further information regarding each utility's plan to meet requirements of §§ 40-2-125.5 and 25-7-105(1)(e)(VIII)(A), C.R.S.;
2) Discussion regarding whether and, if so, how each utility intends to address policy initiatives in Governor Jared Polis's "Roadmap to 100% Renewable Energy by 2040 and Bold Climate Action" (the "Governor's Roadmap");
3) Identification of anticipated organized market information as applied to each scenario and additional discussion regarding the result of the Joint Utilities' participation in potentially separate regional markets, including anticipated participation in energy imbalance market or day-ahead markets;
4) Information regarding the effects of technology advancements, specifically regarding energy storage capabilities over time;
5) Clarifications regarding Distributed Energy Resources (DER) and Distributed Generation (DG) terminology and concepts; and

6) Additional explanation regarding the elimination of the gas Local Distribution Company (LDC) as described in Public Service's Scenario No. 5 in the 20-Year Conceptual Scenario Report.

Since the Commission issued its Decision, the Joint Utilities have conferred and collaborated to develop this Supplemental Joint Rule 3627 Transmission Report ("Supplemental Joint Rule 3627 Report"). While the Joint Utilities have determined that there are a number of areas of alignment between each of the utilities, there are other areas that warrant more individualized responses to the Commission's six requests. For this reason, the Joint Utilities are submitting individual responses to some questions and combined responses to others. The Joint Utilities provide their responses to the Commission's six supplemental information requests in Section III below.

In its Decision, the Commission made two additional findings that the Joint Utilities address in this Supplemental Joint Rule 3627 Report. First, the Commission stated:

> The Joint 10-Year Transmission Plan and 20-Year Conceptual Scenario Report as supplemented with information required by this Decision shall include all models used and an explanation and copy of model outputs. Additionally, updates shall include discussion of the Basis of Plan, Identified Issues, and any Resource Requirements including Costs, Quality Metrics, and Stakeholder Register.

Second, the Commission stated:

> The Utilities are reminded to provide documentation verifying all information referenced in the Joint 10-Year Transmission Plan and 20-Year Conceptual Scenario Report, including supplemental information and, as appropriate, in an accessible format via a direct link to a utility or utility-maintained website consistent with Rule 4 CCR 3627(a)(III).

The Joint Utilities address these elements of the Commission's Decision in Sections III and IV below.

II. Supplemental Information Requested by Decision No. C20-0213-I

In this Section of their Supplemental Joint Rule 3627 Report, the Joint Utilities present their responses to each of the six categories of information requested by Commission Decision No. C20-0213-I.

A. Clarification and Further Information Regarding Each Utility's Plan to Meet the Requirements of §§ 40-2-125.5 and 25-7-105(1)(e)(VIII)(A), C.R.S

Through Decision C20-0213-I, the Commission directed the Joint Utilities to provide "supplemental information such that the Commission can review the Joint 10-Year Transmission Plan and 20-Year Conceptual Scenario Report with regard to recent statutory changes in § 40-2-125.5(3), C.R.S., that require reductions in carbon dioxide by 2030, and foreseeable public policy initiatives."[1] Each utility responds in turn, below.

i. Black Hills' Response

Section 40-2-125.5(3), C.R.S., has various clean energy targets for a "qualifying retail utility." A "qualifying retail utility" is a "retail utility providing electric service to more than five hundred thousand customers in this state or any other electric utility that opts in... ."[2] Black Hills does not meet this statutory definition of a "qualifying retail utility." In addition, Black Hills has not opted in to the statutory requirements, as permitted by § 40-2-125.5(3)(b), C.R.S. Accordingly, the clean energy targets of § 40-2-125.5(3), C.R.S., are not currently applicable to Black Hills.

Though the clean energy targets of § 40-2-125.5(3), C.R.S., do not apply to Black Hills, Black Hills is exploring whether its opting in to the statutory requirements would be in the best interests of customers. In order to make that determination, Black

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[1] Proceeding No. 20M-0008E, Decision No. C20-0213-I, (mailed date April 7, 2020), page 6, ¶16

[2] Section 40-2-125.5(2)(c)(I), C.R.S.

Hills will need to have clarity on the major components associated with Clean Energy Plan methodologies and targets. Specifically, Black Hills will need clarity on the type of sales (either wholesale or retail) that govern the 2005 baseline.[3] In addition, Black Hills will need clarity on the proper methodologies by which to assess historical, current, and future carbon dioxide emissions. These issues have not yet been decided. However, Black Hills understands that the Air Quality Control Commission (AQCC) of the Colorado Department of Public Health and Environment (CDPHE) will be providing the necessary clarity on these issues either through rulemaking proceedings or by providing guidance documents. As the AQCC brings clarity to these issues, Black Hills will be able to determine if the best interests of its customers are served by opting in to the statutory requirements.

Regardless of the clean energy targets, Black Hills has already, and is continuing to make, significant strides in reducing its greenhouse gas emissions. Black Hills has no coal generation on its system, has met the State's 30 percent Renewable Energy Standard (RES) requirement, and is proposing to add significant new renewable resources. Specifically, in Proceeding No. 19A-0660E, Black Hills has pending before the Commission the Renewable Advantage project, where Black Hills is hosting a request for proposals for new renewable and storage resources of up to 200 MWs to dramatically increase renewable penetration and lower customer bills. Black Hills is well suited to further reduce carbon dioxide and greenhouse gas emissions.

From a transmission perspective, Black Hills has not at this time determined a need to develop new transmission to assist in bringing online renewable resources to reduce greenhouse gas emissions. For example, in Proceeding No. 19A-0660E, concerning Renewable Advantage, Black Hills has received competitive bids for

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[3] *Id.* at 40-2-125.5(3)(a)(I), C.R.S. ("By 2030, the qualifying retail utility shall reduce the carbon dioxide emissions associated with electricity sales to the qualifying retail utility's electricity customers by eighty percent from 2005 levels.").

large-scale renewable and storage resources, and these proposed resources seek to interconnect with the Black Hills' system at points on already existing or planned transmission infrastructure. Black Hills has not identified new transmission necessary to assist in meeting emission reduction policies, targets, or goals.

ii. Tri-State Response

Colorado Revised Statute § 40-2-125.5(3) requires qualifying retail utilities to meet certain clean energy targets related to reductions in carbon dioxide emissions associated with retail electricity sales. Tri-State is not a qualifying retail utility as defined by statute and it has no retail electricity sales. As a result, the clean energy targets set forth in the statute do not apply to Tri-State. Tri-State anticipates that carbon dioxide and greenhouse gas emission reduction requirements being developed presently by the AQCC will apply to Tri-State and will guide Tri-State's emission reduction efforts associated with its wholesale electricity sales to its Colorado Members.

Notwithstanding the inapplicability of this statute to Tri-State, and while the AQCC's efforts continue, Tri-State is moving forward with its Responsible Energy Plan ("REP"), a transition to clean energy that will expand renewable generation and reduce greenhouse gas emissions while ensuring reliable, affordable, and responsible electricity for its member cooperatives and public power districts ("Member Systems"). The REP commits Tri-State and its Member Systems to significant reductions in emissions of carbon dioxide attributable to Tri-State's electricity sales to Tri-State's Colorado members, including eliminating 100 percent of emissions from our Colorado coal facilities by closing Craig Station and the Colowyo Mine by 2030. By 2030, and relative to 2005 levels, Tri-State will reduce carbon dioxide emissions in Colorado by 90 percent from generation it owns or operates in Colorado, and by 70 percent with respect to electricity delivered to Tri-State's Colorado Members.

These emission reductions are combined with a commitment to a precedent-setting investment in renewable energy resources. By 2024, Tri-State is bringing over 1 gigawatt of wind and solar resources online, meaning 50 percent of the energy Tri-State's Member Systems consume will come from renewables.

Emission reductions associated with the REP will be addressed through resource planning efforts, which, upon approval by the Commission, are an input into transmission planning efforts. The implementation of the REP and Tri-State's approved Electric Resource Plan (ERP) will require detailed analysis of identified resource retirements and resource additions by network customers. Transmission planners must ensure that the transmission system continues to reliably serve identified network customer load. Tri-State has been leading and participating in joint planning studies through the Colorado Coordinated Planning Group (CCPG) to explore transmission system improvements needed to accommodate additional renewable resource development across the state of Colorado while maintaining system reliability which will further support carbon dioxide reductions.

iii. Public Service Response

As a Qualifying Retail Utility under § 40-2-125.5(3)(I), C.R.S., Public Service will bring forward its clean energy plan to reduce the carbon dioxide emissions from its electricity business by 80 percent below 2005 levels by 2030 in its next ERP filing. This Clean Energy Plan will build on its Colorado Energy Plan, approved under the most recent ERP (Proceeding No. 16A-0396E), which will result in the early retirement of two coal-fired generating facilities with a combined generating capacity of approximately 660 MW, the addition of approximately 1,100 MW of wind generation, approximately 700 MW of solar generation and development of 275 MW of large-scale battery storage. The Colorado Energy Plan alone will transform our electric system to more than fifty percent renewable energy by 2026 and is anticipated to achieve a 60 percent reduction in carbon dioxide emissions compared to 2005 levels.

Public Service's clean energy strategy focuses on reducing emissions from fossil fuel generating resources, increasing investment in renewable energy and storage resources, reliable integration of increasing amounts of renewables, continued energy efficiency efforts, and use of advanced technologies. These focus areas reflect a strategic priority for Public Service and its parent company, Xcel Energy, which is to be a leader in transitioning toward cleaner energy. Transmission development will be a critical element for Public Service in the continued transition to cleaner energy resources (renewable generation) – both as it executes on the approved Colorado Energy Plan, and as it develops and implements its forthcoming Clean Energy Plan.

Historically, conventional generation has been located somewhat independently of the fuel source, which could be delivered to the generation site via pipeline and/or rail system. In contrast, renewable generation is critically dependent on location-specific renewable resources for its energy production and thus may be located hundreds of miles away from the load center. In order to support the continued development of renewable resources from the wind- and solar-rich areas of the state, it is important that the transmission system be developed to reliably accommodate these renewable resources.

As part of Public Service's planning process and as considered in developing in Public Service's latest Rule 3627 Report, Proceeding No. 20M-0008E, there are multiple drivers to the planning process, including accommodation of new resources, retirement of existing resources, compliance with state and federal rules and standards, replacement of aging infrastructure, public policy initiatives and, most importantly, maintaining a reliable and affordable electric grid. When possible, Public Service endeavors to take advantage of opportunities to develop projects that can simultaneously support a combination of these goals.

Historically, Public Service's transmission planning process has relied on a resource need to drive the development of transmission plans. However, with the declining costs of renewables and state policy in favor of renewables, Public Service continues to look at resource plans to fill supply shortages due to demand growth, but also to transition to a cleaner electric generation footprint. Going forward, transmission will be an integral component of achieving both Public Service's and the State of Colorado's clean energy goals. Our transmission planning process will consider the possibility of new resource acquisitions in potentially disparate or remote parts of our region. Between this need to look to new resource areas, and the fact that the Rush Creek Gen-Tie is fully loaded, transmission infrastructure and planning will undoubtedly play an increased role in future resource planning and acquisitions.

Public Service recognizes that better and earlier integration of transmission planning into the resource planning process will be critical going forward as it looks to achieve 80 percent carbon reduction by 2030 as part of its next ERP. Since the 2016 ERP, Public Service's Transmission Planning and Resource Planning groups have been actively collaborating on how to better align their respective processes for future ERPs. This includes earlier identification to Public Service's transmission planners of the size and location of potential resources needed to meet public policy initiatives, so that Public Service can better plan the transmission necessary to accommodate these new resources and reconsideration of what Senate Bill 07-100 provided for transmission to be built in advance of identified generation resources in the identified Renewable Energy Zones.

Public Service's Transmission Planning and Resource Planning departments are coordinating efforts to generally identify the actions that will be necessary to meet Public Service's carbon reduction goals under § 40-2-125.5(3)(I), C.R.S. As part of that process, Transmission Planning has conducted analyses of the potential stand-alone generation injection capabilities of various locations on Public Service's transmission system. Identifying stand-alone generation injection capability is the first step to understand how the existing transmission system might accommodate development of new clean energy resources such as wind and solar. Identifying and maximizing opportunities to utilize the existing transmission system can potentially reduce future transmission costs.

Looking beyond the existing transmission system, in the Joint 10-Year Transmission Plan, Public Service identified and described conceptual new transmission plans that have been developed through the coordinated planning process and that could lay the framework for new transmission infrastructure to support Clean Energy Plan goals. These conceptual plans include the Weld-Rosedale-Box Elder - Ennis 230 & 115 kV Transmission Lines and the Weld County Transmission Expansion, the Lamar Front Range Transmission Project, and the San Luis Valley Project. Using the stand-alone injection capabilities described above along with these conceptual new transmission plans, Public Service is assessing different pathways for how it could achieve the carbon reduction targets of § 40-2-125.5(3)(I), C.R.S through combinations of actions including early coal retirements, reduced coal operations, additional renewable resources (utility scale and distributed) additional storage technologies, and continued expansion of energy efficiency programs, while also maintaining a high level of system reliability.

Through a coordinated effort, Transmission Planning and Resource Planning are utilizing the stand-alone generation injection locations and the conceptual new transmission plans to develop portfolios for analysis that meet the Company's clean energy goals. Preliminary analyses are being conducted using generic cost and performance information for renewable, storage, and other generation technologies, which, in combination with coal-related actions, could be part of a Public Service Clean Energy Plan that will be brought forward to the Commission for approval in the future. Ultimately, the specifics of Public Service's preferred Clean Energy Plan will not be known until Public Service completes its Phase II competitive solicitation evaluation process as part of its next ERP and reports the results of that process to the Commission. This is anticipated to occur in 2022.

Through these preliminary analyses, Public Service has been able to identify several common transmission system criteria violations, as well as criteria violations unique to each conceptual carbon reduction portfolio studied. Transmission Planning presented the common transmission system criteria violations at the May 21, 2020 CCPG meeting. These include overloads in the Denver Metro area due to an increase in power transfer into the load center, and the Pawnee to Story 230 kV line overload due to an increase of power flow on this line. Another set of transmission projects that may be needed to help Public Service meet its carbon reduction targets include the networking of the Rush Creek Gen-Tie (which was studied as part of the Lamar Front Range Task Force Study), and the Northern Greeley Area Transmission Plan (which aligns with the Weld County Transmission Plan).

Transmission Planning will make available specific criteria violations as well as the necessary upgrades as they become available at future CCPG meetings, FERC 890 meetings and through other stakeholder outreach meetings that may be scheduled.

B. Discussion Regarding Whether and, if so, How Each Utility Intends to Address Policy Initiatives in the Governor's Roadmap

On May 30, 2019, Colorado Governor Jared Polis released his administration's "Roadmap to 100% Renewable Energy by 2040 and Bold Climate Action" (the "Governor's Roadmap"). Among other aspects of Gov. Polis's vision, the Governor's Roadmap identifies the goal of Colorado being powered by 100 percent renewable energy by 2040. The Governor's Roadmap also describes the policies and actions the Administration is taking and will take to advance this goal, as well as how the 100 percent by 2040 goal relates to other aspects of the Governor's vision. While Governor Polis has issued a number of Executive Orders that complement the Governor's Roadmap,[4] the Roadmap itself is not an Executive Order nor does it have the force of law comparable to recently enacted energy legislation such as House Bill 19-1261 and Senate Bill 19-236.

Notwithstanding the fact that the Governor's Roadmap does not create an enforceable obligation, the Joint Utilities acknowledge it sets forth a present public policy initiative of the current Administration, which could lead to future policy initiatives. As such, the Joint Utilities agree that it is appropriate to consider the Governor's 100 percent by 2040 goal in connection with their conceptual long-range

[4] *See, e.g.*, Executive Order D 2019 016, Concerning the Greening of State Government.

scenarios developed under Commission Rule 3627(e). Therefore, as directed by the Commission, the following supplemental information "addresses whether and how the Utilities plans to make progress toward meeting the Governor's Roadmap goal of providing consumers with energy generated from 100 percent clean energy resources by 2040."[5]

i. Black Hills Response

Black Hills appreciates the Governor's Roadmap as a policy perspective on increasing renewables and reducing greenhouse gas emissions. The Governor's Roadmap can be used to inform individual litigated proceedings at the Commission. For instance, on May 8, 2020, in Proceeding No. 20A-0159E, Black Hills submitted its Ready EV Plan, representing Black Hills' first Transportation Electrification Plan. The Governor's Roadmap addresses policies to support transportation electrification. The Commission and interested parties can thus examine how the Ready EV Plan furthers the Governor's policy prerogatives in that individual proceeding.

As another example, the Governor's Roadmap addresses the policy need to reduce carbon dioxide emissions. The Commission and interested parties can address that policy in the Company's ongoing Renewable Advantage proceeding, Proceeding No. 19A-0660E, as well as in future ERP proceedings.

Focusing on transmission, the Governor's Roadmap supports consideration and evaluation of enhanced electricity markets in Colorado. Toward that end, in December 2019, Black Hills announced the intent to join the California Independent System Operator (CAISO) Western Energy Imbalance Market (WEIM). Black Hills, together with the other participants to the Joint Dispatch Agreement, are continuing their work to enter this market. The Commission and interested parties can examine

[5] Commission Decision No. C20-0213-I, ¶ 18.

Black Hills' proposal to join the CAISO WEIM in comparison to the policy issues related to enhanced electricity markets contained in the Governor's Roadmap.

ii. Tri-State Response

On January 15, 2020, Tri-State announced its REP, which will dramatically and rapidly advance the association's clean energy portfolio and its programs to serve its Member electric cooperatives and public power districts, including its 18 Colorado Member Systems. A key component of the REP is the investment of over $1 billion in contracts for 1,000 MW of renewable wind and solar projects by 2024, and up to an additional 1,000 MW of renewable energy projects by 2030.

As of the date of this Supplemental Report, Tri-State provides 31 percent renewable energy to its Colorado Members. Under the REP, that amount will increase to 50 percent by 2024. Furthermore, Tri-State has set a goal of striving to reach 100 percent clean energy resources in Colorado by 2040.

These aspects of the REP are complemented by Tri-State's announcement that it will eliminate 100 percent of the carbon dioxide emissions from its coal-fired power plants in Colorado by 2030. Additionally, Tri-State has put in place programs to provide its Member Systems greater flexibility in developing local renewable energy projects, including community solar generation. In the context of Rule 3627, these aren't just "conceptual long-range scenarios," these are present actions intended to achieve the goals of the REP.

Tri-State anticipates that it may begin discussing steps associated with the REP as early as its next ERP that is scheduled to be filed with the Commission on December 1, 2020, and will follow-up on those steps and progress made in its next ERP that is scheduled to be filed on June 1, 2023.

In the interim, Tri-State believes that the three conceptual long-range scenarios discussed in its portion of the Utilities' Joint 2020 Rule 3627 Report are consistent with and complement the vision of the Responsible Energy Plan. Scenario #1 – Increased Role of Distributed Energy Resources – contemplates the increased role of a number of technologies that constitute renewable energy resources as defined in § 40-2-124(1)(a)(VII), C.R.S. Whether developed by Tri-State or its Colorado Members, such resources will play a role in meeting the Governor's Roadmap goal of 100 percent clean energy by 2040. Scenario #2 – Increased East-West Interconnection – contemplates the possibility of new DC-Tie facilities and new DC transmission lines between the Eastern and Western Interconnections. Such improvements will provide an opportunity for Tri-State to tap-into renewable energy resources in the east through its participation in the Western Energy Imbalance Service so as to complement the renewable energy resources developed in Colorado to serve its Members' load. Finally, Scenario #3 – Increased Energy Storage – contemplates significant advancement and growth of energy storage technology that not only could, in appropriate circumstances, defer or replace traditional transmission projects, but also potentially assist in the integration of variable renewable energy resources. Each of Tri-State's 2020 conceptual long-range scenarios represent potential system improvements that would support the goals of the REP.

iii. Public Service Response

The Governor's Roadmap proposes aggressive action to achieve 100 percent renewables across the Colorado economy by 2040. Xcel Energy's, and in turn, Public Service's, plans for a 100 percent clean energy future by 2050 will make significant progress toward this overarching objective of the Roadmap. Xcel Energy's practical yet proactive approach considers the technology limitations and factors in the challenges that will need to be solved to reach the goal of a 100 percent clean energy portfolio by 2050, while spurring the necessary innovations to support this transition. Long before 2050, Public Service's plans to achieve 80 percent carbon reduction by 2030 will undoubtedly make significant strides toward the Roadmap's 2040 goal. And resource plans occurring every four years along the way can continue to allow the Commission, utilities and stakeholders to calibrate the cost and feasibility of progress toward 2040 or 2050 targets.

Public Service believes its work toward the clean energy targets outlined in § 40-2-125.5(3), C.R.S. will undoubtedly provide lessons learned that Public Service can build upon and apply toward its 100 percent clean energy by 2050 goal. Conceptually in the next 30-year timeframe, Public Service will focus on increasing renewable resources, managing existing customer load, developing a more robust transmission system, and incorporating new, dispatchable, carbon-free technologies.

For example, Public Service is actively exploring energy storage solutions through ongoing pilots through its Innovative Clean Technologies program first approved in Proceeding No. 09A-015E. Through these pilots, Public Service is assessing the capabilities of battery energy storage systems on its distribution grid and increasing its understanding of how battery energy storage can help manage impacts on the distribution system with high penetration of photovoltaic generation. Public Service is also pursuing Commission approval of more involvement and exploration in this area through its proposed Community Resiliency Initiative (CRI) in Proceeding 19A-0225E. If approved, the CRI would develop seven microgrid projects totaling 6 MW and 15 MWh of Company-owned energy storage system projects to proceed pursuant to § 40-2-203(4), C.R.S. Public Service anticipates that these targeted, community-based microgrid projects will enhance safety, reliability, and resiliency of the electric grid while expanding the integration and utilization of battery technology on the Public Service's system.

It is anticipated that an increase in energy storage will be required to achieve 100 percent clean energy future. Understanding this need, Public Service will seek opportunities to develop energy storage throughout the system. As advancements in energy storage technologies are developed, energy storage solutions will also begin to emerge as solutions to various system issues such as regulation, frequency response and contingency reserves. Through the CCPG and the Energy Storage Work Group, Public Service will continue to develop its understanding and share its findings of energy storage and non-transmission alternatives with neighboring utilities and stakeholders.

In addition to pursuing energy storage solutions, reducing on-peak energy usage through energy efficiency programs and new or innovative rate design can also play an important role in reducing systemwide carbon dioxide emissions and other pollutants, while delaying the need for system upgrades. Public Service's Demand-Side Management program has a longstanding and successful track record of helping customers manage their energy usage more efficiently. On the rate design front, Public Service has recently implemented a dedicated Commercial electric vehicle (EV) rate that encourages customers to shift from on-peak to off-peak EV charging, which was approved through Proceeding No. 19AL-0290E, and Public Service has also proposed a default time-of-use rate for its Residential electric customers through an advice letter filed in Proceeding No. 19AL-0687E.

Public Service continues to evaluate opportunities to build transmission, which will encourage and accommodate the electrification of other industries such as the transportation and oil and gas industry. Both of these efforts hold promise to improve air quality and the health of the communities we serve. Public Service anticipates that its Transportation Electrification Plan (TEP), recently filed in Proceeding No. 20A-0204E, will help enable Governor Polis' vision through decreasing carbon dioxide emissions and other pollutants from the transportation sector, and through its TEP, Public Service is proposing several initiatives that facilitate charging optimization, which can help improve the integration of renewables onto our system and reduce system-wide carbon dioxide emissions through encouraging a shift from on-peak to off-peak charging.

Public Service views successful implementation of its Colorado Energy Plan, described above, as a springboard that will position us to better understand the reliability implications of integrating and accommodating significant new renewable generation resources onto our system in a cost-effective manner. Public Service understands that the ultimate transition away from traditional, centralized fossil fuel plants will require new and innovative transmission and distribution solutions to bring resources online from previously undeveloped parts of the region. This transition also presents added challenges for transmission planning, including the potential need to traverse geographically sensitive and unique areas, navigate a complex array of siting and land rights issues (including locally and federally protected lands), and address the potential for increased wildfire risk. Conversely, these projected transmission developments will provide an opportunity to take advantage of new available technologies or innovative applications of existing technologies while further considering non-transmission alternatives.

Though it is difficult to anticipate the impact the actions outlined in the Governor's Roadmap and Public Service's efforts that support this vision will have in aggregate from a transmission planning perspective, Public Service will maintain a steady approach to safely modernizing the grid with renewable energy reliably, while keeping customers' energy bills low.

C. Identification of Anticipated Organized Market Information as Applied to Each Scenario

According to the Commission's Decision, the "Utilities shall include additional analysis regarding organized market considerations. Specifically, updates should address considerations of organized market analysis that were made in each respective scenario. The Utilities shall identify participation in potentially separate regional markets. Additional discussion regarding the result of this divergent participation, including anticipated participation in energy imbalance market or day-ahead markets, should be addressed further for consideration and comment."[6]

i. Joint Utilities' Response

Organized markets continue to evolve within the Western Interconnection and, over the last year, Black Hills, Public Service, and Tri-State have publicly declared their intent to participate in separate energy imbalance markets. Public Service, and the Joint Dispatch Agreement (JDA) participants, including Black Hills, announced in

[6] Proceeding No. 20M-0008E, Decision No. C20-0213-I, (mailed date April 7, 2020), page 7, ¶19

December of 2019 their intention to pursue negotiations on an implementation agreement with CAISO for its Balancing Authority (BA) to participate in the WEIM. Tri-State, along with Basin Electric Power Cooperative (Basin Electric) and the Western Area Power Administration (WAPA), announced in September 2019 their intention to become members of Southwest Power Pool's (SPP) Western Energy Imbalance Service (WEIS) market.

Participation in separate energy imbalance markets is not expected to alter the process under which the utilities subject to Rule 3627 plan their transmission systems. Each utility will continue to provide transmission service under its own Open Access Transmission Tariff (OATT), subject to the Federal Energy Regulatory Commission's (FERC) orders governing the administration of their respective OATTs, including FERC Orders 888, 890, and 1000. Black Hills, Public Service, and Tri-State will continue local planning coordination through CCPG, and will continue to be members of the WestConnect planning region as part of their regional planning obligation under FERC Order 1000.

While participation in energy imbalance markets should not affect the way transmission planning is coordinated and completed, it may provide opportunities for each utility to examine opportunities beyond traditional system reliability metrics. Both the WEIM and the WEIS are real-time energy imbalance markets with nodal or Location Marginal Pricing (LMP), which provides a level of price transparency that may assist with identifying opportunities for transmission projects that provide greater transfer capability with other market participants, congestion relief, or more efficient generation siting.

Black Hills, Public Service, and Tri-State will continue to examine future opportunities for market development, which may include expanding their participation into a full Regional Transmission Organization (RTO), or other day-ahead market construct. A discussion of each utility's perspective on future organized market constructs, including RTOs, is addressed below.

ii. Black Hills Response

Black Hills has continually analyzed opportunities for participation in a broader regional market, whether through our participation in the now defunct Mountain West Transmission Group (MWTG), or working with our BAs and their other customers to analyze new opportunities such as the WEIM and WEIS. Internal analysis takes place in a cross-functional manner across many parts of the organization. The impacts of regional markets can touch every facet of the organization, and most importantly, our customers. Savings and costs related to participation in regional markets are passed directly to customers, so it is imperative that any regional market option demonstrates *long-run net benefits*.

Since the breakup of the MWTG the two most viable options for regional market participation have been the WEIM offered by the CAISO, and the WEIS offered by SPP. Both the WEIM and WEIS are energy imbalance markets where real-time energy imbalances are handled through a Security Constrained Economic Dispatch (SCED). Transmission service is similar in both markets (though not identical), and leverages unutilized transmission capacity in real-time to deliver imbalance energy, thereby maximizing the use of transmission capacity that would otherwise be a sunk cost. The decision to join an energy imbalance market is largely driven by the BA, which is responsible for providing energy imbalance service through either their OATT, or a contractual arrangement with their customers.

Black Hills is a BA customer of Public Service and participates in the JDA along with Platte River Power Authority (PRPA), and Colorado Springs Utilities (CSU). Public Service and the other JDA partners agreed to participate in a joint production cost study during 2019 to examine potential energy savings. The results of that study were used in conjunction with other quantitative and qualitative analysis as inputs into the Public Service announcement in late 2019 that the JDA entities would look to begin negotiations with the CAISO to join the WEIM.

Black Hills did not consider regional market scenarios in its 20-year conceptual scenario planning due to the high uncertainty surrounding participation in an RTO, and the fact that energy imbalance markets are not expected to significantly impact the planning process that currently exists between Colorado utilities. Even under the scenario that Colorado utilities participate in multiple energy imbalance markets, local and regional transmission planning would continue to function as it does today. An energy imbalance market does have the potential to increase projects driven by economics or public policy that may be considered within the planning process, including projects that increase transfer capability within the regional market footprint. Black Hills is continuing to examine how such projects would be analyzed in the future, assess our capabilities to perform such planning, and determine how economic or policy driven transmission planning can be incorporated to benefit our customers in the future. Under that assumption Black Hills focused the 20-year conceptual scenarios on areas that were determined to have higher levels of certainty around how our systems may be impacted from a reliability perspective within the 10 to 20-year planning horizon, whether Black Hills is participating in a regional market or the status quo were to continue.

iii. Tri-State Response

Tri-State views an RTO as the linchpin to a clean energy transition and an important and necessary element in the implementation of its REP. An RTO would create cost sharing, a joint OATT, and new planning opportunities that will enable the Rocky Mountain Region to more efficiently and cost-effectively integrate more renewables onto the transmission system, improve transmission system utilization, increase transmission system reliability, and allow Tri-State's Member Systems access to a much larger portfolio of renewable energy. As noted previously, Tri-State is already a member of SPP and placed its Eastern Interconnection facilities in SPP's RTO years ago, resulting in a positive experience and cost savings. Tri-State is joining seven other utilities in SPP's Western Energy Imbalance Service market and represents a step closer to a full RTO. Tri-State believes that some form of an organized market will be in place in Colorado within the 20-year conceptual scenario horizon.

Tri-State believes that the Increased East-West Interconnection long-range scenarios discussed in its portion of the Utilities' Joint 2020 Rule 3627 Report is consistent with the vision of an organized market. Scenario #2 – Increased East-West Interconnection – contemplates the possibility of new DC-Tie facilities and new DC transmission lines between the Eastern and Western Interconnections. Such improvements will provide an opportunity for Tri-State's Member Systems to tap-into renewable energy resources in the Eastern Interconnection. This would be accomplished through its participation in the WEIS or a full-organized market so as to complement the renewable energy resources developed in Colorado to serve its Members' load.

From Tri-State's perspective, the impact of separate organized markets on transmission planning will be minor as local and regional transmission planning would likely occur in a similar fashion as performed today through the CCPG to facilitate coordination and stakeholder input. Due to the highly interconnected nature of the transmission system involving multiple jurisdictional and non-jurisdictional transmission providers, continued coordination of transmission planning and operational efforts would be vital on the local and regional levels. The creation of separate RTOs within Colorado, or within the Western Interconnection for that matter, would not hinder transmission planning as demonstrated by the fact that multiple RTOs exist across the Eastern Interconnection and coordinate effectively. Should separate organized markets develop within Colorado, coordination would continue and, if needed, evolve to continue to ensure plans are developed in a joint, open, and transparent fashion.

iv. Public Service Response

As stated in the 20-year Report, Public Service continues to be involved in regional energy market development. Public Service, along with Black Hills and, most recently, CSU, participates in the JDA. The JDA is a simplified form of an energy imbalance market that dispatches least-cost energy between the JDA participants based on an hourly, system-marginal price and unused available transmission capacity. In mid-2019, the JDA participants commissioned a joint study to evaluate and compare the costs and benefits for participation in the WEIM sponsored by the CAISO or the SPP WEIS. As described in Proceeding No. 19M-0495E, the JDA participants decided to join the CAISO WEIM. WAPA, Tri-State and Basin Electric made their decision to join the SPP WEIS.

Energy imbalance markets reduce production costs in real-time, which enables participants to capture some of the benefits seen in RTOs with fully organized markets. Unlike an RTO structure, transmission service providers within the CAISO EIM and SPP WEIS will continue to operate and control their own transmission systems in accordance with their existing OATTs. Energy imbalance participants provide generation information to the market operators to improve generation dispatch and use transmission service pursuant to the individual OATTs within the footprint. In an RTO environment, each individual OATT is eliminated in favor of a single OATT (or, “regional tariff”) administered by the RTO. A regional tariff allows transmission customers to move power throughout the footprint without paying individual transmission owner tariffs (*i.e.*, rate pancaking), which enables improved generation dispatch by market services, leading to greater production cost benefits. The drawback of a regional tariff includes the cost shifts that occur with lower cost systems subsidizing higher cost systems, the administrative costs of the RTO, and issues around transmission planning and cost allocation, among others.

CAISO is working with stakeholders to evaluate the feasibility of adding a day-ahead component to the WEIM without an RTO structure to enable further production cost benefits for participants. Public Service is involved in this evaluation, but currently there are no concrete proposals for development of the day-ahead component to CAISO WEIM.

Public Service has no expectation of when or if an RTO will be developed and control the transmission system of the former MWTG footprint, or under what terms and conditions that transition may ultimately occur. With that in mind, Public Service’s Scenario #1 did not identify any transmission enhancements that would be likely under an RTO environment for the 20-year conceptual scenario. Furthermore, Public Service has proposed no transmission enhancements that are associated with its participation in the WEIM.

At this time, there are no concrete plans to increase transmission transfer capability between the JDA participants and other CAISO WEIM utilities. Public Service will be evaluating the opportunities for future capability, whether based on new transmission construction or acquisition of transmission service, and such evaluations will include more robust considerations of production cost savings, renewable energy integration benefits, and savings in contingency reserves obligations. Public Service expects that if any new transmission upgrades arise as a result of this evaluation, they would be brought to the CCPG, WestConnect, and other stakeholder review committees for further evaluation. Such projects could ultimately be included in future Rule 3627 reports in either the 10 or 20-year plans.

D. Information Regarding the Effects of Technology Advancements, Specifically as Applied to Each Scenario

According to the Commission's Decision, the Commission requests "supplemental information describe[ing] whether and if so how, the Utilities will address the anticipated effects of technology advancements, particularly regarding storage capabilities, on transmission and the proposed 10 and 20-year plans."[7]

i. Joint Utilities' Response

The Joint Utilities do not anticipate that technology advancements will impact the planned transmission projects outlined in the 10-year transmission plan. However, the conceptual transmission projects listed in the later years of the 10-year plan may benefit from future advancements in technology. The Joint Utilities through CCPG are developing guidelines and a process to evaluate non-transmission alternatives.

[7] Proceeding No. 20M-0008E, Decision No. C20-0213-I, (mailed date April 7, 2020), page 7, ¶20

The guidelines and process are intended to assist project sponsors and engineers in evaluating and comparing benefits of transmission system upgrades with non-transmission alternatives (*i.e.* non-wire alternatives). In future reporting, we anticipate that a single term will be agreed upon among the Joint Utilities. To ensure the Joint Utilities remain up to date with storage advancements, they will continue evaluate competing non-transmission alternatives for new transmission projects through their individual utility project development process.

Transmission planning and the projects developed by the utilities' transmission planning groups primarily focus on the reliable delivery of energy generated by a resource to load centers, which often are some distance away from the generating resource. Transmission project drivers include load growth, new generation sources, and aging infrastructure, among others. Transmission projects are developed to ensure reliability and compliance with applicable North American Electric Reliability Corporation (NERC) reliability standards. The Joint Utilities' existing transmission planning processes evaluate energy storage systems on their ability to possibly mitigate the need for new transmission projects and provide supporting services to the grid. An example of a supporting service is the ability to provide reactive power and voltage support to ensure reliable system performance. This benefit is often addressed with traditional capacitor or reactor projects. The costs and proven benefit of capacitor or reactor projects has not been surpassed by any of the recent advancements in energy storage technology. Further, it is possible energy storage systems may be able to defer new transmission and distribution projects in the future by providing energy in strategic areas to keep loading on nearby transmission lines below specified ratings. According to a 2018 U.S. Energy Information Administration's ("EIA") report on U.S. Battery Storage Market Trends (the "EIA Report"), the megawatt capacity installed and attributed to transmission or distribution project deferral was 45.1 MW of the 551.7 MW capacity total reported.[8]

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[8] U.S. Battery Storage Market Trends, EIA (May 2018), p. 23, a*vailable at*
https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

In contrast, the amount of installed capacity attributed to frequency regulation is 486.7 MW. This point highlights the physical limitations associated with energy storage systems as they compare to transmission development. However, other benefits such as frequency regulation and providing ramping/spinning reserves suit today's energy storage performance attributes well. The Joint Utilities anticipate the existing limitations in capacity and duration will continue to improve and thus the Joint Utilities will continue to evaluate non-transmission alternatives when developing future transmission projects.

The EIA Report further finds that over 80 percent of U.S. large-scale battery storage power capacity is currently provided by batteries based on lithium-ion chemistries.[9] It is anticipated that technology advancements will continue to progress in lithium-ion technology. Further, continued development of flow battery technology is another energy storage technology which shows promise. Flow batteries' overall capacity is a function of the tank size in which the chemical solutions are stored. Flow batteries are characterized by their long cycle life and are projected by EIA to have a long operational lifetime.[10] The Joint Utilities anticipate these technologies will continue to enhance their ability to accommodate a variety of future resources and improve system flexibility.

The price of storage technology is generally declining. According to the EIA Report, "battery systems with shorter durations will typically have lower normalized power capacity costs ($/kW) than batteries with longer nameplate durations. The opposite is generally true when examining normalized energy capacity costs ($/kWh), as the total system costs for longer-duration systems are spread out over a larger basis of stored energy. Nonetheless, the range of normalized cost values is driven by technological and site-specific requirements."[11] Thus, though the cost of energy

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[9] *Id* at 8.

[10] *Id*.

[11] *Id* at 13.

storage is trending downward, data should be considered based on a variety of specific attributes and a degree of caution should be taken when applying this broadly. The Joint Utilities will continue to evaluate non-transmission technologies as alternatives to future transmission projects in their 10-year plan and future plans.

Each Utility provides additional information in turn, below.

ii. Black Hills Response

Black Hills has begun integrating storage into its transmission consideration processes and planning. To further consideration of storage capabilities and costs, Black Hills commissioned a study undertaken by HDR to provide a technical overview of the current state of the energy storage industry, including types of commercially available energy storage technology that may be applicable as non-wire alternatives in Black Hills' transmission and distribution planning processes. This study has been filed in Proceeding No. 20-0176E, which is Black Hills' Rule 3207 Report proceeding. The study is also included as Appendix A to this supplemental report.

The HDR analysis reviewed commercially available NWAs and its applicability to projects. For cost comparison, the cost of an energy storage system using lithium-ion batteries was used because of its availability and ease of use. The results of the HDR analysis indicated that while non-wire alternatives, and particularly Battery Energy Storage Systems (BESS), have made significant improvements in availability and technology. However, they still have difficulty on a general basis performing as cost-effective alternative solutions for transmission or distribution system projects.

Black Hills expects energy storage to impact future distribution and transmission plans. At this time, Black Hills asserts that storage may pose greater opportunities for customer benefits on the distribution system, as opposed to the transmission system. This finding can change if full RTO participation is pursued. As Black Hills continues to assess and consider energy storage, its future transmission plans, including 10 and 20-year scenarios, may be shaped by this resource.

iii. Tri-State Response

Tri-State regularly considers technology advancements, such as energy storage systems, as part of its transmission planning process. Other potential technology advancements that are considered in transmission planning include, but are not limited to, Flexible AC transmission system (FACTS) devices, high-temperature low-sag (HTLS) line conductors, and dynamic line rating equipment. All of which are meant to enhance stability, controllability, and/or power transfer capability on the transmission system. FACTS devices include series and shunt reactive devices, which influence transfer capability and/or voltage stability/control, respectively. HTLS line conductors and dynamic line rating equipment have the potential to increase the transfer capability of a line, offering the potential to delay the need for new transmission line construction.

In particular, energy storage, in appropriate cases, has the potential to defer or replace more traditional transmission projects by providing congestion relief. While energy storage may be helpful in firming up variable renewable energy resources, it is unlikely to replace transmission projects primarily related to connecting such resources to the grid, or to serve new loads. Energy storage costs have been falling quickly, however, the energy storage capacities necessary to address transmission issues are generally very large.

The considerations of technology advancements, such as energy storage systems, in relation to near-term transmission planning projects are summarized in Tri-State's annual filing under Commission Rule 3206. Energy storage will likely play an increasing role in Colorado's energy mix, and is a consideration in Tri-State's resource planning. Should the price of energy storage continue to fall, storage may become a more significant component of Tri-State's transmission system planning as well.

iv. Public Service's Response

Public Service does not anticipate an immediate impact on current planned projects in the 10-year plan. However, it is reasonable to expect that conceptual projects in the outermost years of the project plan may be impacted or modified by the introduction of new technology advancements. To the extent this occurs, Public Service would update the Commission in future Rule 3627 filings.

As mentioned above, performance advancements in lithium-ion battery and flow battery technology coupled with more competitive costs will contribute significantly to the increase in use and implementation of these technologies. As battery technology becomes more prevalent, opportunities may emerge for batteries to assist in mitigating operational and planning issues on the transmission system such as primary frequency response, regulation, and contingency spinning.

Further, Public Service anticipates that renewable resource technologies will continue to advance in terms of efficiency. For example, one manufacturer claims up to 35 percent increase in production with the use of bifacial solar modules versus that of a single sided panel.[12] The bifacial solar module exposes both the front and back of the solar cells thus increasing the energy production. It is reasonable to expect that existing plants may consider this new technology as a future upgrade to their existing site. Likewise, as power electronics such as inverters and power point trackers advance, an opportunity may present itself to reduce losses and capture more energy out of an existing plant's footprint. Advancements in power electronics also show promise in supporting transmission line compensation and may be used an alternative to traditional methods to influence power flow.

Public Service will continue to evaluate advancements in energy storage and non-wires alternatives to address potential applications on its transmission system.

[12] *See* https://www.prismsolar.com/our-products.

E. Clarifications Regarding DER Resources and DG

In its Decision, the Commission indicated that it would find clarifications with respect to usage of the terms "DER" and "DG" to be useful, stating "[s]upplemental clarification and analysis should explain the similarities and differences regarding the presented terminology provided in the respective DER scenarios and DG scenario, including specifically Public Service clarifying its use of DER as opposed to DG. In addition, Utilities should clarify whether and how modeling is being conducted for the respective scenarios regarding the DER and DG concepts."

Within Paragraph 21 of its Order, the Commission requests clarification of usage of the terms Distributed Energy Resources (DER) and Distributed Generation (DG) by Black Hills, Tri-State, and Public Service in their 20-year Scenarios 1, 1, and 3, respectively. First, these Scenarios are presented at a high level, essentially as conceptual discussions to "assist with the identification of strategic choices that utility planners, project developers, regulators, and advocates may reasonably need to consider over a 20-year time period."[13] Consistent with past practice, quantitative analysis was not presented by the utilities.

Second, the usage of these two terms in the particular context of these three Scenarios has more similarities than differences. The term "DER" can have a very broad meaning, inclusive of distributed solar, distributed storage, energy efficiency, demand response, electric vehicles, distributed fuel cell generation at customer sites and possibly more potential types of distributed resources. However, all three utilities' Scenarios in this area focused more on solar DG, which is arguably the most prominent form of DER today. For example:

- Black Hills' first listed Assumption in its Scenario #1 ("Significant Penetration of Distributed Energy Resources") is "Public policy initiatives couple with continued public interest toward rooftop/-community solar may increase the current distributed capacity." The second Assumption is "Typical *power*

[13] Proceeding No. 18M-0080E, Public Service Company of Colorado, Tri-State Generation and Transmission, and Black Hills Energy Combined Rule 3627 20-Year Report, page 1.

output curves for renewable resources may interact with typical load curves to cause flows and voltages not seen in the current system" (emphasis added). Black Hills' discussion generally relates to increased distributed generation, though the concept is teed up as DER.

- Similarly, TSGT's Scenario #1 ("Increased Role of Distributed Energy Resources") focuses strongly on distributed generation. The first Assumption therein is "The price of Solar PV continues to fall." The second Assumption is "There is continued interest and increased penetration of community-based and behind-the-meter business models that make solar PV available to more consumers." Clearly, solar DG is a strong element of this scenario. Much of TSGT's analysis of this Scenario under "Potential Benefits and Transmission Impacts to Colorado" speaks directly to increases in distributed generation implicitly or explicitly.
- Public Services' Scenario #3, ("High Penetration of Distributed Generation"), as the Commission observes, focuses on increased solar DG. Here, Public Service focuses in a more explicit way on distributed solar generation in this Scenario, but the Black Hills and TSGT Scenarios are, in effect, not dissimilar.

In summary, the Joint Utilities agree that DERs encompass a broad set of applications and technologies in the utility sector. In developing these particular Scenarios in this 3627 Report, however, the three utilities cover fairly similar ground in focusing on distributed solar at the high level presented for the Rule 3627(e) long-range scenario. Further, over a 20-year time horizon, the multiple types of DERs could evolve in different directions far beyond the work scope and objective of the 3627 report. This is not to say that broader DER scenario analysis is not useful. Monitoring and ongoing scenario thinking around a broad set of DERs is appropriate for future Rule 3627 planning and other planning or scenario activities at the Commission.

Additionally, as a point of clarification for Paragraph 21 of the Order, while modeling was *not* performed by each of the utilities for these 20-year conceptual scenarios regarding DER and DG, it should be mentioned that CCPG *did* perform 2040 conceptual power flow modelling[14] and this modelling included DG. As inputs to the

[14] *See* 2020 Rule 3627 20-Year Conceptual Scenario Report, page D-5 and following.

CCPG 2040 modelling, each of the utilities provided their mix and type of renewable resources that existed in 2017, and the renewable resources they anticipate adding to their system by 2040, to fulfill their energy requirements under Colorado's statutory RES. DG is a renewable resource to comply with RES. Modelling of DG was therefore conducted through the CCPG 2040 conceptual power flow modelling for the 20-Year Conceptual Scenario Report.

Each Utility provides additional information in turn, below

i. Black Hills Response

Black Hills considers "DG" to be a reference to renewable generators in Colorado, both retail and wholesale, to comply with the state's RES. Black Hills has transitioned to using the term "DER" in its documentation to refer to the interconnection of DG and other technologies such as energy storage systems. Transmission planning has started group discussions on the need to coordinate models for the purpose of studying potential back feed on the transmission system associated with DER loads. This is a new process and still in the discussion phase and is planned to be investigated further as the distribution planning group continues to refine and implement new distribution planning processes.

ii. Tri-State DER Response

From its perspective and for purposes of its transmission planning, Tri-State views the terms "distributed energy resource" and "distributed generation" as being synonymous. From a transmission planning perspective, DER is generally located behind the meter on a Member System's distribution network.

Existing, and future, DER are reflected in the transmission planning model's load models, which have load and distribution generation components. Within the transmission planning models, the addition of DER generally appears as a reduction in network load. DER are typically variable in nature so the load models have the ability to toggle the status of the DER from on-line to off-line, allowing the transmission system to be planned appropriately for the scenarios where the DER are on-line or off-line. Further, the addition of DER can alter the transient performance of the transmission system in a given area, which is factored into transmission planning studies through Western Electricity Coordinating Council's (WECC) dynamic load models, which factor in DER, if it exists.

An aspect of Tri-State's REP is an emphasis on increased flexibility for Members to self-generate, which could lead to more behind-the-meter DER. Due to modeling initiatives at the WECC level which the Utilities participate in, transmission planning models will continue to be updated to reflect DER as levels increase.

iii. Public Service's Response

The Commission requests "specifically Public Service clarifying its use of DER as opposed to DG."[15] Public Service presumes the Commission intended instead to say "clarifying its use of DG as opposed to DER," as DG is the term the Company used in its Scenario #3: High Penetration of Distributed Generation. Public Service selected the term "DG" versus "DER" in its Scenario #3 because it was focused in that Scenario on the potential transmission planning implications of DG, especially DG solar. Public Service notes that distributed solar is the most prominent DER generation resource in its service territory at this point - on Public Services' system alone, there are over 50,000 installations of on-site solar distributed generation. DG solar could have the general effect of decreasing the amount of large-sale generation planned or built, and thus the amount of transmission investments built, but with a potential countervailing effect of requiring incremental distribution system investments.

By contrast, a broader definition of DER in scenario planning could have different effects depending on the DER in question. For instance, a scenario focusing on electric vehicles as DERs could increase the need for large-scale generation and transmission planning and development. This scenario, and potentially many others

[15] Proceeding No. 20M-0008E, Decision No. C20-0213-I, (mailed date April 7, 2020), page 8, ¶21

possible under the broader umbrella of DERs, was not explored by Public Service in its Scenario #3. Public Service recognizes that it is likely that further exploration of a broader set of DERs in future scenario or planning exercises may be merited. But again, Public Service, like the other two utilities, focused primarily on DG solar in this particular Scenario in this report. Public Service also briefly explored a broader set of DERs under its Scenario #4, which covers the 100% Renewable Energy by 2040 goal set forth in the Governor's Roadmap.

F. Further Detail Concerning Local Distribution Company

According to the Commission's Decision, the Commission seeks additional explanation regarding the elimination of the gas LDC described in Public Service's Scenario No. 5.[16] The Commission requests that Public Service expand on its explanations and reasoning that culminated in Scenario No. 5, to allow for a better understanding of the underlying assumptions it made in presenting this possibility.

i. Public Service Response

Public Service Scenario #5: LDC Gas Phaseout

In its Decision No. C20-0213-I at paragraph 22, the Commission requests that "Public Service should expand on its explanations and reasoning that culminated in Scenario No. 5, to allow for a better understanding of the underlying assumptions it made in presenting this possibility." Public Service discussed the main arguments for the inclusion of Scenario #5 in the original Rule 3627 Report, and we appreciate the Commission's interest and the opportunity to expand on our rationale for including this scenario. While Public Service is not aware of any specific proposals to phase out any gas LDC system in the U.S., or any Colorado proposals to limit any gas LDC systems, cities and municipalities in other parts of the country have put forward and, in some cases, approved policy proposals that would limit or block new

[16] Proceeding No. 20M-0008E, Decision No. C20-0213-I, (mailed date April 7, 2020), page 8, ¶22

growth of gas LDC systems, as the examples in our scenario highlighted. Here in Colorado, policies such as House Bill 19-1261, may eventually create some level of scrutiny on greenhouse gas emissions from customers of the LDC sector, which the Company reiterates is different than what Public Service would be responsible for with regard to its own methane emissions.[17] It remains unclear if rules regulating customer emissions will or will not be contemplated by the State in the context of House Bill 19-1261.

However, in order to demonstrate the significant potential impacts to the transmission system, Public Service included this LDC phaseout scenario in the original Rule 3627 Report. Public Service believes the gas LDC phaseout scenario would be unlikely and extremely challenging to implement. As highlighted in the Scenario, significant additional generation and thus transmission would be needed to replace the service provided by the Company's gas LDC system. To illustrate how dramatic this change could be, on the 2019 maximum daily output day, our gas system delivered 2,139,420 mmBtu.[18] The electrical equivalent of this would be 26,000 MW, or more than three times Public Service's peak electrical load.[19] Heat pump efficiency gains might reduce this figure, but it would still clearly be significant. To further illustrate, the Scenario pointed out how Public Service's electric system would likely shift from summer peaking to winter peaking in order to serve the new electrical load created by heating needs in the winter, which could also impact the need for more intermittent renewable energy resources. Public Service also points out that we currently serve, and are obligated to serve, 1.54 million natural gas customers in Colorado. The scenario to eliminate the LDC would thus require well over a million individual decisions to fuel switch away from gas to another energy source.

[17] The Roadmap appears to create a 100 percent renewable energy goal across the economy, implying all sectors, by 2040.

[18] Source: Public Service Company of Colorado Form 10-K, page 7.

[19] 2,139,420 mmBtu * 1000000 btu/mmBtu ÷ 3413 btu/kWh ÷ 1000 kWh/MWH ÷ 24 hours/day = 26,119 MW.

In summary, Public Service offered this LDC phaseout scenario in the original Rule 3627 Report as a bookend to illustrate the dramatic nature of the potential implications on the transmission system. Public Service believes this scenario is unlikely, and that any future significant trend to reduce usage of the gas LDC system, if it comes to pass, would be many years away. Further, Public Service believes that progress can be made to reduce the greenhouse gas footprint of customers of the existing gas system through measures such as increased natural gas energy efficiency measures, voluntary beneficial electrification programs, renewable natural gas, and continued efforts to reduce methane leakage on the LDC system as well as upstream of it. We are seeking to do all of these things. This scenario is informative for the ongoing public policy discussions.

III. Models and Model Outputs

According to the Commission's Decision, "[t]he Joint 10-Year Transmission Plan and 20-Year Conceptual Scenario Report as supplemented with information required by this Decision shall include all models used and an explanation and copy of model outputs. Additionally, updates shall include discussion of the Basis of Plan, Identified Issues, and any Resource Requirements including Costs, Quality Metrics, and Stakeholder Register."[20]

The Joint Utilities respond as follows:

As an initial matter, the Joint Utilities cannot provide the models used in the Joint 10-Year Transmission Plan and 20-Year Conceptual Scenario as they are considered Critical Energy Infrastructure Information (CEII) and require non-disclosure agreements with WECC to be provided. Additionally, model outputs cannot be provided due to each model's wide variety of model outputs, some of which are considered CEII, and are specific to the respective model.

[20] Proceeding No. 20M-0008E, Decision No. C20-0213-I, (mailed date April 7, 2020), page 8, ¶23

To provide additional context, however, the Joint Utilities believe it may be helpful to provide an overview of how transmission planning is conducted, how transmission models are utilized, and the purposes of such planning. This information may be useful in understanding the fundamental differences between transmission planning and resource planning, and demonstrating why transmission plans are developed, in part, to meet the specific needs identified through resource planning rather than conceptual resource scenarios.

Transmission Planning involves detailed analyses of deterministic planning models developed by the WECC to identify transmission system improvements or additions needed to meet reliability, load serving, or generation needs over a 10-year planning period. The Joint Utilities participate with WECC in the development of the planning models by providing detailed modeling data for existing transmission infrastructure, estimated modeling data for future transmission infrastructure, and expected load and resource information based on forecasts provided by each utility's network customers. Each planning model reflects projected or starting power system conditions (including loads, generation, and topology) for a specific point in time, such as Heavy Summer (expected summer peak loading) with high or low renewables.

WECC develops approximately a dozen planning models each year, typically including the following:

- Five operating cases
    - Reflecting expected system conditions within the next year
        - Heavy/Light Summer
        - Heavy/Light Winter
        - Heavy Spring
- Two 5-year cases
    - Reflecting expected system conditions 5-years into the future
        - Heavy Summer
        - Heavy Winter
- Two 10-year cases
    - Reflecting expected system conditions 10-years into the future

    - Heavy Summer
    - Heavy Winter
- Two or Three Specialized Cases
  - Reflecting specified system conditions in the 5- or 10-year timeframe
    - For example, high renewable generation dispatch in light load conditions.

The WECC planning models are available for download on WECC's website at www.wecc.org once the requisite non-disclosure agreements are executed. The planning models are developed to model "book end" (peak load, minimum load) snapshots of expected system conditions up to 10 years into the future, as well as snapshots of specialized operating conditions (such as high renewables) that may occur, to be utilized in detailed planning studies. Planning models provide numerous types of outputs related to transmission system modeling and performance, however only reflect the system conditions observed in the snapshot in time the model is set up to reflect.

The transmission system, in general, is planned for projected worst-case scenarios, which would be the peak load system conditions leading to only heavy summer and winter loading planning models in the five and 10-year horizons. When performing studies, transmission planners will generally only make adjustments to specific area generation and/or load levels, unless system modeling corrections are required. These adjustments change the model to reflect a desired stressed system condition based on the needs of the study. Sensitivity studies are commonly performed on specific planning models; however, they reflect only a snapshot of specific operation conditions for use in evaluating transmission system reliability.

The planning model inputs are generally fixed values reflecting existing transmission system equipment. Additionally, planning models are developed and utilized solely to evaluate system reliability under specific stressed operating conditions, and do not include economic considerations such as operating costs or the social cost of carbon. To properly evaluate economic considerations and identify cost savings, models need to reflect the variable nature of load and resources over a full year, or multiple years, of hourly operating points, rather than the specific "point-in-time" operating conditions found in planning models based on fixed load and generation values.

By comparison, resource planning models are stochastic in nature and include variable inputs (including generator operating costs, transmission costs, carbon costs, and load levels, among others) and allow hourly simulations throughout a projected year or years within a single model. The resource plan modeling process allows optimization of resource costs and determination of production cost savings through congestion relief, amongst others. As the Commission approves resource plans, resource information is provided to the transmission planners for inclusion in the WECC planning models for analysis.

The project management terms Basis of Plan, Identified Issues, and Resource Requirements including Costs, Quality Metrics, Stakeholder Register, are directly related to the implementation of individual transmission projects identified in the 10-Year Transmission Plan. However, these terms are not typically used within transmission planning and in the development of the Joint Utilities' 10-Year transmission plan. The basis of the Joint Utilities' 10-Year transmission plan are the WECC planning models utilized to study system performance and the impacts of forecasted system changes (load growth, generation, etc.). Identified issues, from a transmission planning perspective, are analogous to system performance violations/limitations and their associated cause (*e.g.* load growth). To mitigate "Identified Issues" in transmission planning, transmission alternatives are identified and compared by one or more factors. These factors are analogous to Quality Metrics and can include cost, load-serving capability, generation-injection capability, and constructability, and are utilized to select a preferred alternative. A Stakeholder Register within transmission planning is similar to transmission providers impacted by a specific transmission project, also known as affected systems, and independent stakeholders who participate and provide input in transmission planning through CCPG meetings and study groups, Rule 3627 outreach meetings, and FERC 890 meetings.

The Joint Utilities' 10-Year Transmission Plan includes transmission developments needed to meet "Identified Issues", which are related to meeting reliability, load-serving, generation needs, and/or public policy requirements. The identification of the transmission developments involves detailed analysis of most, if not all, of the WECC planning models developed each year, applying NERC Transmission Planning (TPL) contingency definitions to identify potential system performance violations. The WECC planning models serve as the Basis of the Utilities' 10-Year Transmission Plan. System performance violations generally appear in five and 10-year models allowing adequate time to validate the violation, study potential mitigations, and identify the appropriate solution. Reliability projects in each utility's Transmission Plan are identified to mitigate system performance violations, which can be thermal or voltage in nature, through detailed analysis and are generally the effect of native load growth. Load-serving projects in each utility's Transmission Plan are identified to serve native load growth, which requires the addition or expansion of existing load-serving facilities.

Generation projects in each utility's Transmission Plan are identified through transmission expansion planning to accommodate conceptual resource development or, more commonly, through Generator Interconnection Studies utilizing the same WECC planning models. Pursuant to FERC Order 845, these generator interconnection base models and assumptions are made available upon request once the requisite non-disclosure agreements are executed with the respective Company. Generator Interconnection Studies are performed by the utilities in accordance with their respective OATTs, and allow for unbiased access to the transmission system. However, transmission planning does not site the potential generation in Generator Interconnection Studies. Interconnection Customers specify each potential generator's point of interconnection. Transmission plans to accommodate generators without specific site locations could lead to transmission development in areas that do not meet the needs of a utility's network customers or that contradict a resource plan approved by the utility's regulator.

Public Policy requirements can influence transmission planning directly and indirectly. An example of a direct influence on transmission planning is SB07-100, which required the designation of Energy Resource Zones (ERZs) and the development of plans for the construction or expansion of transmission facilities necessary to deliver electric power consistent with the timing of the development of beneficial energy resources located in or near such zones. An example of an indirect influence on transmission planning are public policy requirements associated with resource plans, and their associated Resource Requirements. Resource plans, as approved, are provided to the transmission planners by each utility's network customers, and are subsequently included in WECC planning models, which form the Basis of each 10-Year Transmission Plan.

A 20-year planning model reflecting peak and off-peak conditions is developed through CCPG from a 10-year WECC planning model. The 20-year planning models reflect projected renewable energy development based on current RES requirements for investor-owned utilities and cooperatives, as well as conceptual transmission projects. The projected renewable development in the 20-year model that may not be part of an approved resource plan is assumed to exist within the model to meet renewable energy targets. The assumed renewables are located based on known areas with potential for renewable development and can at times require conceptual transmission projects to incorporate the resources into the model.

Detailed analysis is not performed on the 20-year planning models due to the increasing levels of uncertainly looking beyond the five and 10-year horizons. The levels of uncertainly increase greatly beyond the one to five-year timeframe due to many unknown variables that may impact the transmission system in the future, such as future resource plans, state legislation, load growth, and technological advancements, amongst many others. Any single variable could have significant impacts to the model and the associated reliability results, making prudent transmission planning impossible if based on purely long-term models. Long-term models beyond 10 years into the future are best served as informative to help gain insight into potential system needs to maintain reliability. The 20-year planning models are available once required WECC non-disclosure agreements are executed, due to their source WECC planning model data.

IV. Information Verification

Finally, according to the Commission's Decision, "[t]he Utilities are reminded to provide documentation verifying all information referenced in the Joint 10-Year Transmission Plan and 20-Year Conceptual Scenario Report, including supplemental information and, as appropriate, in an accessible format via a direct link to a utility or utility-maintained website consistent with Rule 4 CCR 3627(a)(III)."[21]

The Joint Utilities have reviewed the Joint 10-Year Transmission Plan and 20-Year Conceptual Scenario Report, and have updated their Rule 3627 Ten-Year Transmission Plan to provide documentation in an accessible format via a direct link to a utility or utility maintained website. Accordingly, the Joint Utilities are concurrently providing with this Supplemental Joint Rule 3627 Report an Amended Rule 3627 Ten-Year Transmission Plan.

V. Conclusion

In conclusion, the Joint Utilities respectfully submit this Supplemental Joint Rule 3627 Report and request the Commission issue an Order finding that the Joint Utilities have satisfied their compliance obligations with respect to Rules 3625-3627.

[21] Proceeding No. 20M-0008E, Decision No. C20-0213-I, (mailed date April 7, 2020), page 9, ¶24