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 1, 2022

Table of Contents

ACRONYMS AND ABBREVIATIONS

Acronym or Abbreviation	Term
2020 Plan	2020 10-Year Transmission Plan for the State of Colorado
2022 Plan	2022 10-Year Transmission Plan for the State of Colorado
80x30TF	80x30 Task Force
AC	Alternating Current
ACSR	Aluminum Conductor Steel Reinformed
ACSS	Aluminum Conductor Steel Supported Conductors
AMI	Advanced Metering Infrastructure
AQCC	Air Quality Control Commission
ARPA	Arkansas River Power Authority
ATC	Available Transfer Capability
ATCID	Available Transfer Capability Implementation Document
BE	Beneficial Electrification
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
CCA	Community Choice Aggregation
CCPG	Colorado Coordinated Planning Group
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
DC	Direct Current
DCFC	Direct-current Fast Chargers

Acronym or Abbreviation	**Term**
DER	Distributed Energy Resources
DLR	Dynamic Lines Ratings
DMEA	Delta-Montrose Electric Association
DSC	Distributed Series Compensator
DSM	Demand-Side Management
EPAct	Energy Policy Act of 2005
ERP	Electric Resource Plan
ERP/APR	Electric Resource Plan Annual Progress Report
ERZ	Energy Resource Zone
ESWG	Energy Storage and Non-Wire Alternatives Working Group
EV	Electric Vehicle
EVSE	Electric Vehicles and Charging Equipment
EVSI	Electric Vehicle Supply Infrastructure
FACTS	Flexible Alternating Current Transmission System
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GHG	Greenhouse Gas
HB19-1261	Colorado House Bill 19-1261
HVDC	High Voltage Direct Current
KCEA	K.C. Electric Association
KCEC	Kit Carson Electric Cooperative
kV	Kilovolt
L&R	Load and Resource
LTC	Load Tap-Changing
LTP	Local Transmission Plan
LMP	Locational Marginal Price
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

Acronym or Abbreviation	Term
Order 1000	FERC Order No. 1000 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities
OWM	Organized Wholesale Market
PA	Planning Authority
PAR	Phase Angle Regulator
PIM	Performance Incentive Metric
PNM	Public Service Company of New Mexico
POI	Point of Interconnection
PPA	Power Purchase Agreement
PRPA	Platte River Power Authority
PST	Phase Shifting Transformer
Public Service	Public Service Company of Colorado
PV	Photovoltaic
RE Compliance Plan	Renewable Energy Standard Compliance Plan
REP	Responsible Energy Plan
REPTF	Responsible Energy Plan Task Force
RES	Renewable Energy Standard
RTO	Regional Transmission Organization
SB07-100	Colorado Senate Bill 07-100
SB19-236	Colorado Senate Bill 19-236
SLV	San Luis Valley
SOL	System Operating Limits
SPP	Southwest Power Pool
SSSC	Static Synchronous Series Compensator
STATCOM	Static Synchronous Compensator
SVC	Static VAR Compensator
SWEP	Southwest Weld Expansion Project
TBD	To Be Determined
TCPC	Transmission Coordination and Planning Committee
TEP	Transportation Electrification Plan
TP	Transmission Provider
TPL	NERC Transmission Planning
Tri-State	Tri-State Generation and Transmission Association, Inc.
TRMID	Transmission Reliability Margin Implementation Document
TTC	Total Transfer Capability

Acronym or Abbreviation	Term
UCA	Utility Consumer Advocate
UPFC	Unified Power Flow Controller
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
Western/WAPA	Western Area Power Administration (also WAPA)
WMEG	Western Markets Exploratory Group

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 2022 10-Year Transmission Plan for the State of Colorado ("2022 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 sixth 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 2022 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 2022 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 2022 Plan and the individual transmission projects included in the 2022 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 2022 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 responded to stakeholder feedback.

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 2022 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 2022 Plan and the transmission planning process in general. Examples of public policies and legislation potentially impacting the Companies include various legislation and administrative rules targeting carbon reductions from the electric sector, efforts to electrify transportation and other parts of the economy, incentives and other measures aimed at increasing the use of distributed energy resources, and organized wholesale electric markets.

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 2022 Plan identifies 85 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. Transmission projects included in the 2022 Plan[2]

Map #	Project Name	In-Svc (1)	Cost (MIL)	BH	TS	PS	Other	Purpose
1	Boone-La Junta 115 kV Rebuild	2020	$20.9	√				R
2	Keenesburg Substation – Generation Interconnect (CEPP bid W090)	2020	$0.2			√		G
3	NREL Substation	2020	$12.1			√		G
4	Shortgrass – Cheyenne Ridge 345kV Transmission	2020	$62.4			√		G
5	Shortgrass Switching Station	2020	$22.1			√		G
6	Southwest Weld Expansion Project	2020	$70.0		√			L,R

[2] In-service dates and costs 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. Similarly, cost estimates are subject to change through further project refinement.

Map #	Project Name	In-Svc (1)	Cost (MIL)	BH	TS	PS	Other	Purpose
7	Western Colorado Trans Upgrade	2020	$57.2		√			R
8	Williams Creek 230kV Switching Station	2020	$9.1				CSU	G
9	Airport Memorial-Nyberg 115kV Rebuild	2021	$3.0	√				R
10	Ault 345/230 kV XFMR Replacement	2021	$7.8				WAPA	R
11	Barker Distribution Substation	2021	$39.2			√		L
12	Desert Cove-Fountain Valley-Midway 115kV	2021	$6.4	√				R
13	Falcon-Midway 115 kV Line Uprate	2021	$3.8		√			R
14	Midway KV1A Replacement	2021	$5.5				WAPA	L,R
15	Sisson Project	2021	$18.8		√			L
16	Avery Substation	2022	$12.1			√		L
17	Boone-South Fowler 69/115kV Conversion	2022	$11.8	√				R
18	CEPP Switching Station Bid S085 (Canceled)	~~2022~~	~~$12.0~~			~~√~~		~~G~~
19	Comanche Substation - Generation Interconnect (CEPP bid 077)	2022	$1.8			√		G
20	Del Camino-Slater 115kV Line Uprate	2022	$1.4		√			L,R
21	Greenwood-Denver Terminal 230kV Line	2022	$74.7			√		G,L,R
22	High Point Distribution Substation	2022	$14.4			√		L
23	Hogback Ranch 115kV Substation	2022	$9.9	√				R
24	Midway Substation - Generation Interconnect (CEPP bid 056)	2022	$1.7			√		G
25	Mirasol (formerly Badger Hills) Switching Station (CEPP Bid X647)	2022	$24.2			√		G
26	Nixon-Kelker 230kV Line Uprate	2022	$0.2				CSU	R
27	North Penrose 115kV Distribution Sub	2022	$6.7	√				R
28	South Fowler Substation	2022	$5.1	√				R
29	Tundra (CEPP Switching Station Bid X645)	2022	$22.9			√		G
30	Vollmer Project	2022	$7.1		√			L
31	Bluestone Valley Substation Phase 2	2023	$16.1			√		L

Map #	Project Name	In-Svc (1)	Cost (MIL)	BH	TS	PS	Other	Purpose
32	Cahone – Empire 115kV Line Uprate	2023	$0.9		√			G, R
33	CEPP Transmission Service Network Upgrades	2023	$15.7			√		G, R
34	Fuller Transformer	2023	$5.0				CSU	L
35	Horizon Substation	2023	$31.2				CSU	L
36	Kettle Creek Transformer	2023	$2.0				CSU	L
37	North System Improvements	2023	$16.0				CSU	R
38	Pike Solar and BESS	2023	$5.0				CSU	G
39	Pueblo West 115kV Distribution Sub	2022	$5.4	√				R
40	Rodrigues 115kV Sub	2023	$7.0	√				R
41	South System Improvements	2023	$11.0				CSU	L,R
42	Waterton Expansion (Previously Titan) Distribution Substation	2023	$12.3			√		L
43	West Station-Greenhorn 115kV Line Rebuild	2022	$7.0	√				R
44	West Station to Hogback 115 kV Transmission Project	2023	$24.0	√				L,R
45	Ault-Cloverly 230/115 kV Transmission	2024	$84.7			√		L,R
46	Avon-Gilman 115 kV Transmission	2024	$11.4			√		R
47	Black Hollow Sun (BHS) Project	2024	$8.0				PRPA	G
48	Burlington-Burlington (KCEA) Rebuild	2024	$0.7		√			R
49	CEPP Voltage/Reactive Support	2024	$79.4			√		G
50	Claremont Transformer	2024	$4.0				CSU	L
51	CSU Flow Mitigation	2024	$1.5			√	CSU	R
52	Slater Double Circuit Conversion	2024	$4.1		√			R
53	Stagecoach Switching Station	2024	$11.0			√		G
54	Weld KV1A Replacement and Breaker and Half Project	2024	$5.8				WAPA	R, L
55	Blue Mesa Reactor and Transformer	2025	$4.6				WAPA	R
56	Burlington-Lamar 230 kV Line	2025	$106.5		√			G,L,R
57	Central System Improvements	2025	$90.0				CSU	R
58	Flying Horse Transformer	2025	$2.0				CSU	L

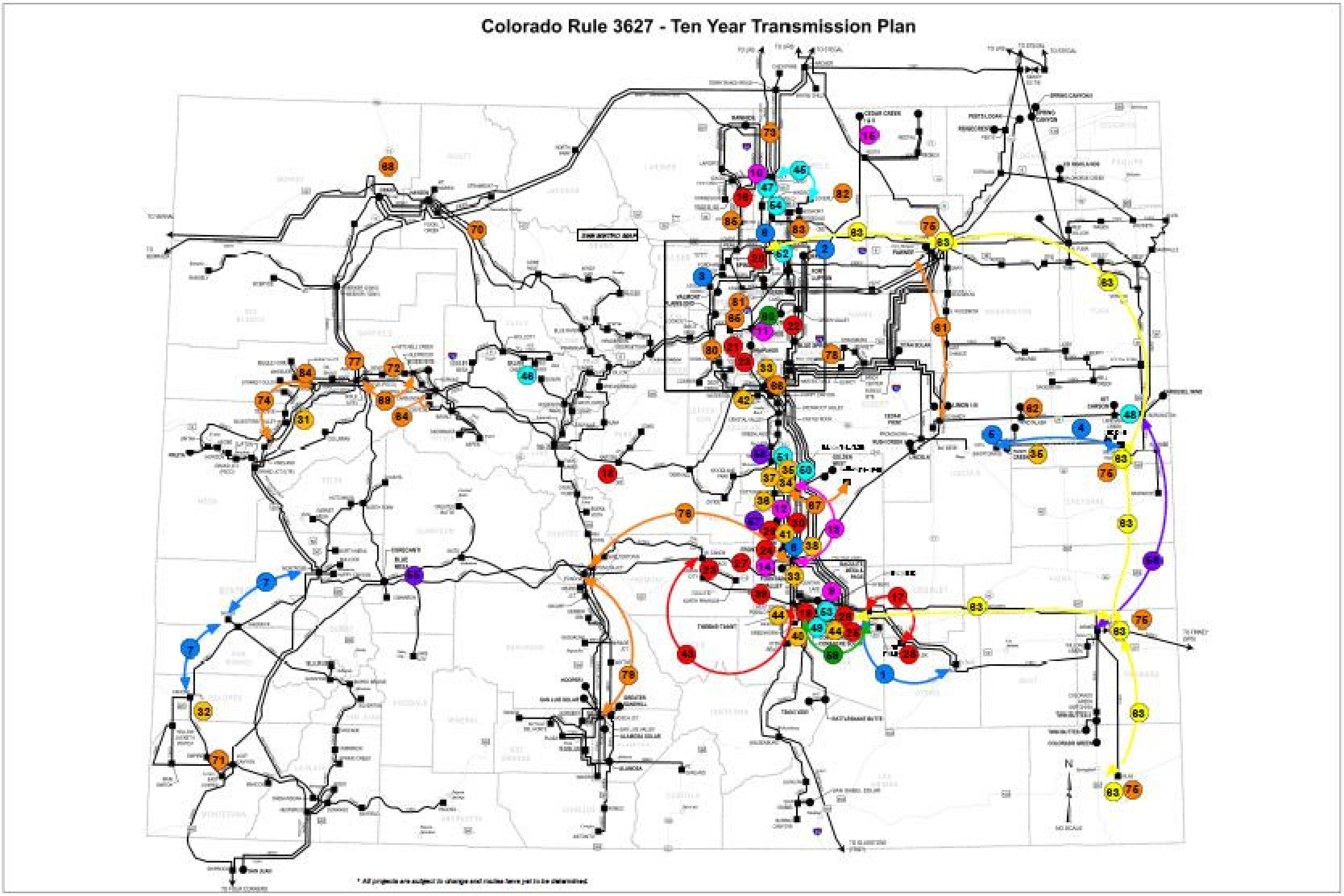
Map #	Project Name	In-Svc (1)	Cost (MIL)	BH	TS	PS	Other	Purpose
59	Boone – Huckleberry 230 kV Line	2026	$40.3		√			G
60	Stock Show Distribution Substation	2026	TBD			√		L
61	Big Sandy – Badger Creek 230 kV Line	2028	$86.4		√			G, R
62	Big Sandy – Burlington 230 kV Line Uprate	2028	$7.7		√			G, R
63	Colorado's Power Pathway (With Optional Segment)	2027	$1,700 ($2,100)			√		G, R
64	Carbondale – Crystal 115 kV Transmission	TBD	TBD			√		R, L
65	Denver Metro Area Upgrades	TBD	TBD			√		G, R
66	Dove Valley Distribution Substation	TBD	TBD			√		L
67	Falcon-Paddock-Calhan 115 kV Line	TBD	$33.4		√			R
68	Gateway South – Craig/Hayden Area Transmission	TBD	TBD			√		R
69	Glenwood-Rifle 115 kV Transmission	TBD	TBD			√		L,R
70	Hayden-Foidel Creek-Gore Pass 230 kV	TBD	TBD			√		R
71	Lost Canyon-Main Switch 115 kV Line	TBD	$22.6		√			L,R
72	New Castle Distribution Substation	TBD	TBD			√		L
73	Northern Colorado Transmission	TBD	TBD			√		R
74	Parachute-Cameo 230 kV #2 Transmission	TBD	TBD			√		L,R
75	Pathway Voltage Control/Support	TBD	TBD			√		R
76	Poncha – Front Range 230 kV	TBD	TBD			√		G
77	Rifle-Story Gulch 230 kV Transmission	TBD	TBD			√		L
78	Sandy Creek Distribution Substation	TBD	TBD			√		L
79	San Luis Valley-Poncha 230 kV[3] Line #2	TBD	TBD		√	√		R,G
80	Solterra Distribution Substation	TBD	TBD			√		L

[3] 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
81	Superior Distribution Substation	TBD	TBD			√		L
82	Weld County Transmission Expansion	TBD	TBD			√		G,R
83	Weld-Rosedale-Box Elder-Ennis 230/115 kV	TBD	TBD			√		L,R
84	Wheeler-Wolf Ranch 230 kV Transmission	TBD	TBD			√		L
85	Wilson Distribution Substation	TBD	TBD			√		L

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

Figure 1. Statewide map of transmission projects in the 2022 Plan



2020

1. Boone - La Junta 115kV Rebuild (BHCE)
2. Keenesburg Sustation General Interconnect(PSCo)
3. NREL Substation (PSCo)
4. Shortgrass - Cheyenne Ridge 345kV Transmission (PSCo)
5. Shortgrass Switching Station (PSCo)
6. Southwest Weld Expansion Project (Tri-State)
7. Western Colorado Trans Upgrade (Tri-State)
8. Williams Creek 230kV Switching Station (New, CSU)

2021

9. Airport Memorial - Nyberg 115kV Rebuild (BHCE)
10. Ault 345/230kV Transformer Replacement (WAPA)
11. Barker Distribution Substation (PSCo)
12. Desert Cove - Fountain Valley - Midway 115kV (BHCE)
13. Falcon - Midway 115kV Line Uprate (Tri-State)
14. Midway KV1A Replacement (WAPA)
15. Sisson Project (Tri-State)

2022

16. Avery Substation (PSCo)
17. Boone - South Fowler 69/115kV Conversion (BHCE)
18. CEPP Switching Station Bid S085 (Cancelled, PSCo)
19. Comanche Substation - Generation Interconnection (CEPP Bid 077) (New, PSCo)
20. Del Camino - Slater 115kV Line Uprate (Tri-State)
21. Greenwood - Denver Terminal 230kV Line (PSCo)
22. High Point Distribution Substation (PSCo)
23. Hogback Ranch 115kV Substation (BHCE)
24. Midway Substation - Generation Interconnection (CEPP Bid 056) (New, PSCo)
25. Mirasol (Formerly Badger Hills) Switching Station (CEP Bid X647)(PSCo)
26. Nixon - Kelker 230kV Line Uprate (CSU)
27. North Penrose 115kV Distribution Sub (BHCE)
28. South Fowler Substation (BHCE)
29. Tundra (Formerly CEPP Switching Station Bid X645) (PSCo)
30. Vollmer Project (Tri-State)
33. Pueblo West 115kV Distribution Sub (New, BHCE)
43. West Station - Hogback 115kV Transmission Project (BHCE)

2023

31. Bluestone Valley Substation Phase-2 (PSCo)
32. Cahone - Empire Line Uprate (New, Tri-State)
33. CEPP Transmission Service Network Upgrades(New, PSCO)
34. Fuller Transformer (New, CSU)
35. Horizon Substation (New, CSU)
36. Kettle Creek Transformer (New, CSU)
37. North System Improvements (New, CSU)
38. Pike Solar and BESS (New, CSU)
40. Rodrlues 115kV Sub (New, BHCE)
41. South System Improvements (New, CSU)
42. Waterton Expansion (previously Titan) Distribution Substation (PSCO)
44. West Station - Greenhorn 115kV Line Rebuild (BHCE)

2024

45. Ault - Cloverly 230/115kV Transmission Project (PSCo)
46. Avon - Gilman 115kV Transmission (PSCo)
47. Black Hollow Sun (BHA) Project (PRPA)
48. Burlington - Burlington (KCEA) Rebuild (Tri -State)
49. CEPP Voltage/Reactive Support (PSCo)
50. Claremont Transformer (New, CSU)
51. CSU Flow Mitigation (CSU)
52. Slater Double Circuit Conversion (New, Tri-State)
53. Stagecoach Switching Station (New, PSCo)
54. Weld kV 1A 230/115kV Xfmr Replacement (New, WAPA)

2025

55. Blue Mesa Reactor & Xfmr Installation (New, WAPA)
56. Burlington - Lamar 230kV (Tri-State)
57. Central System Imrovements (New, CSU)
58. Flying Horse Transformer (New, CSU)

2026

59. Boone - Huckleberry 230kV Line (New, TSGT)
60. Stock Show Distribution Substation (PSCo)

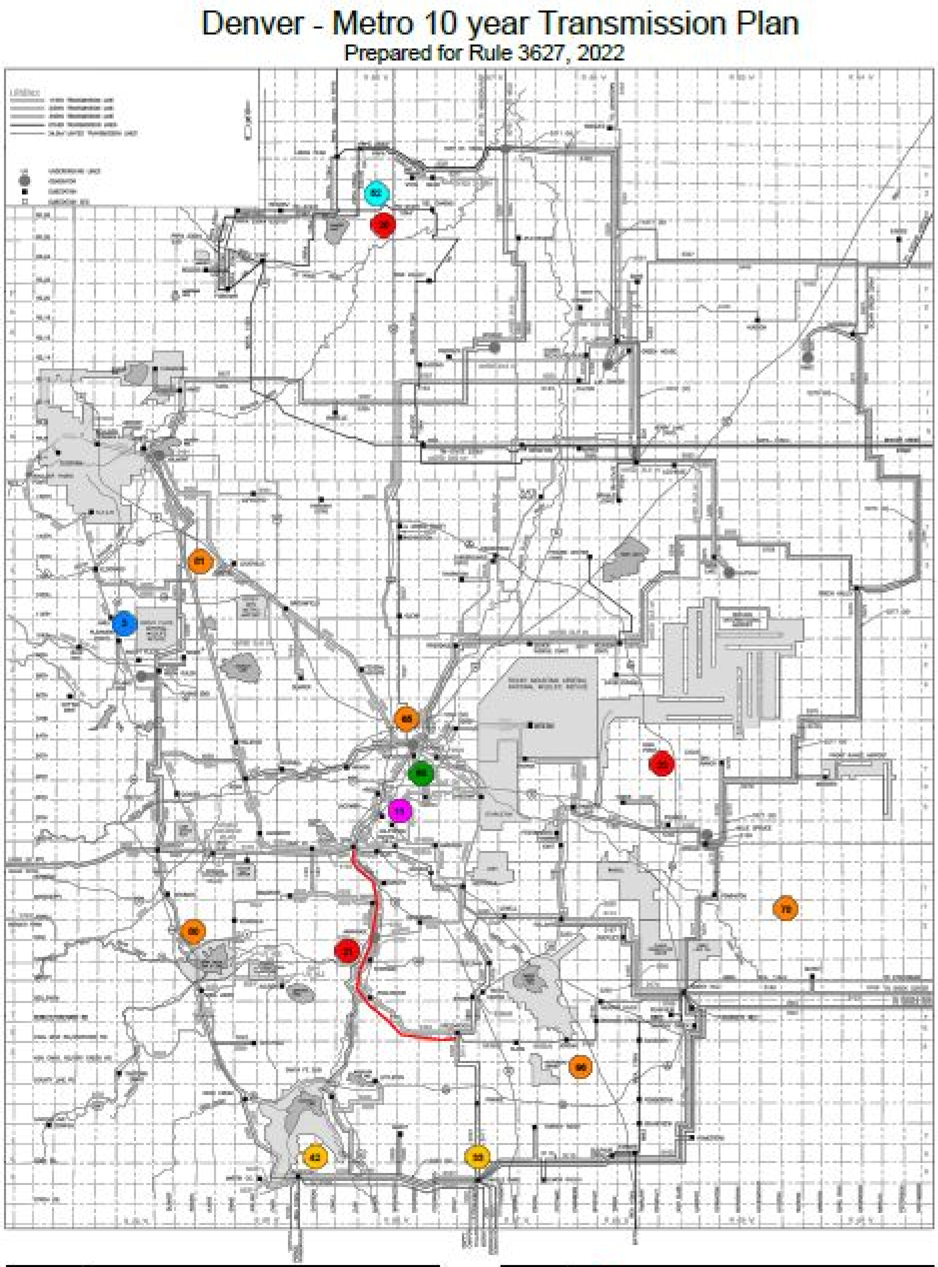
2027

63. Colorado's Power Pathway (New, PSCo)

Beyond 2028 or ISD TBD

61. Big Sandy - Badger Creek (New, TSGT)
62. Big Sandy - Burlington 230kV Line Update (New, TSGT)
64. Carbondale - Crystal Transmission (PSCo)
65. Denver Metro Area Upgrades (TSGT)
66. Dove Valley Distribution Substation (PSCo)
67. Falcon - Paddock - Calhan 115kV (Tri-State)
69. Glenwood - Rifle 115kV (PSCo)
70. Hayden - Foidel - Gore 230kV (PSCo)
71. Lost Canyon - Main Switch 115kV (Tri-State)
72. New Castle Distribution Substation (PSCo)
73. Northern Colorado Transmission (PSCo)
74. Parachute - Cameo 230kV #2 (PSCo)
75. Pathway Voltage Control/Support (PSCo)
76. Poncha - Front Range (New, PSCo)
77. Rifle - Story Gulch 230kV Transmission (PSCo)
78. Sandy Creek Distribution Substation (PSCo)
79. San Luis Valley - Poncha 230kV #2 (Tri-State/PSCo)
80. Solterra Distribution Substation (PSCo)
81. Superior Distribution Substation (PSCo)
82. Weld County Transmission Expansion (PSCo)
83. Weld - Rosedale - Box Elder - Ennis 230/115kV (PSCo)
84. Wheeler - Wolf Ranch 230kV Transmission (PSCo)
85. Wilson Distribution Substation (PSCo)

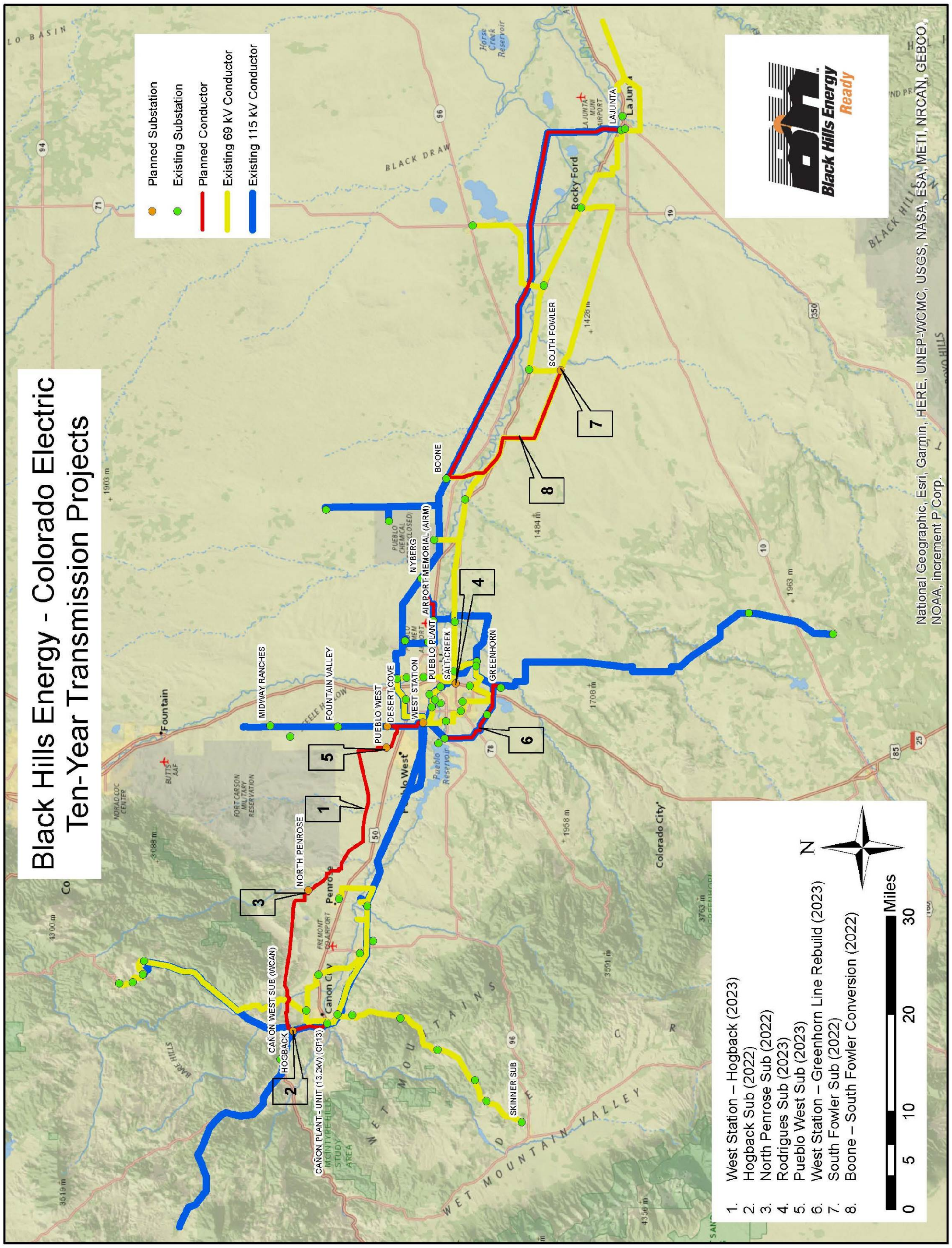
Figure 2. Denver-Metro map of transmission projects in the 2022 Plan



2020	2 Keenesburg Substation - Generation Interconnect (PSCo) 5 NREL Substation (PSCo)
2021	11 Barker Distribution Substation (PSCo)
2022	21 Greenwood - Denver Terminal 230kV Line (New, PSCo) 22 High Point Distribution Substation (PSCo) 28 Del Camino - Slater 115kV Line Uprate (New, Tri-State)
2023	33 CEPP Transmission Service Network Upgrades (New, PSCo) 42 Waterton Expansion (Previously Titan) Distribution Substation (PSCo)

2024	52 Slater Double Circuit Conversion (New,Tri-State)
2026	58 Stock Show Distribution Substation (PSCo)
TBD	65 Denver Metro Upgrades (PSCo) 68 Dove Valley Distribution Substation (PSCo) 70 Sandy Creek Distribution Substation (PSCo) 80 Solterra Distribution Substation (PSCo) 81 Superior Distribution Substation (PSCo)

Figure 3. Pueblo area map of transmission projects in the 2022 Plan



II. Transmission Planning in Colorado

A. Coordinated Planning

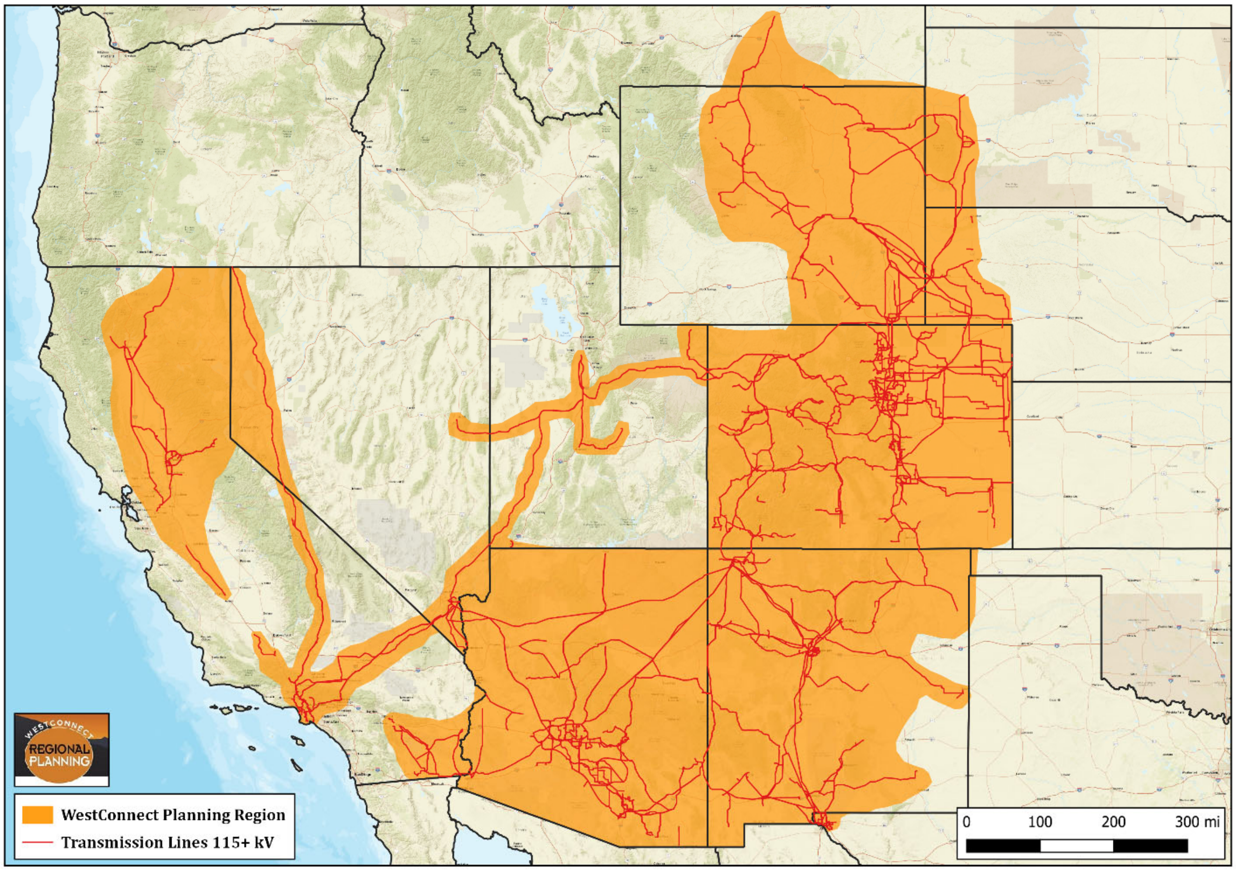
The Companies' transmission planning processes are intended to facilitate the development of electric transmission infrastructure that maintains reliability and meets load growth. Because Colorado does not have a Regional Transmission Organization ("RTO"), each TP in the state is responsible for planning 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 Western Electricity Coordinating Council ("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 three planning "regions"[4] 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: CCPG, Southwest Area Transmission Group, and Sierra Subregional Planning Group.

[4] The other two regions are Northern Grid and the California Independent System Operator.

Figure 4. WestConnect Planning Subregional Group Footprints

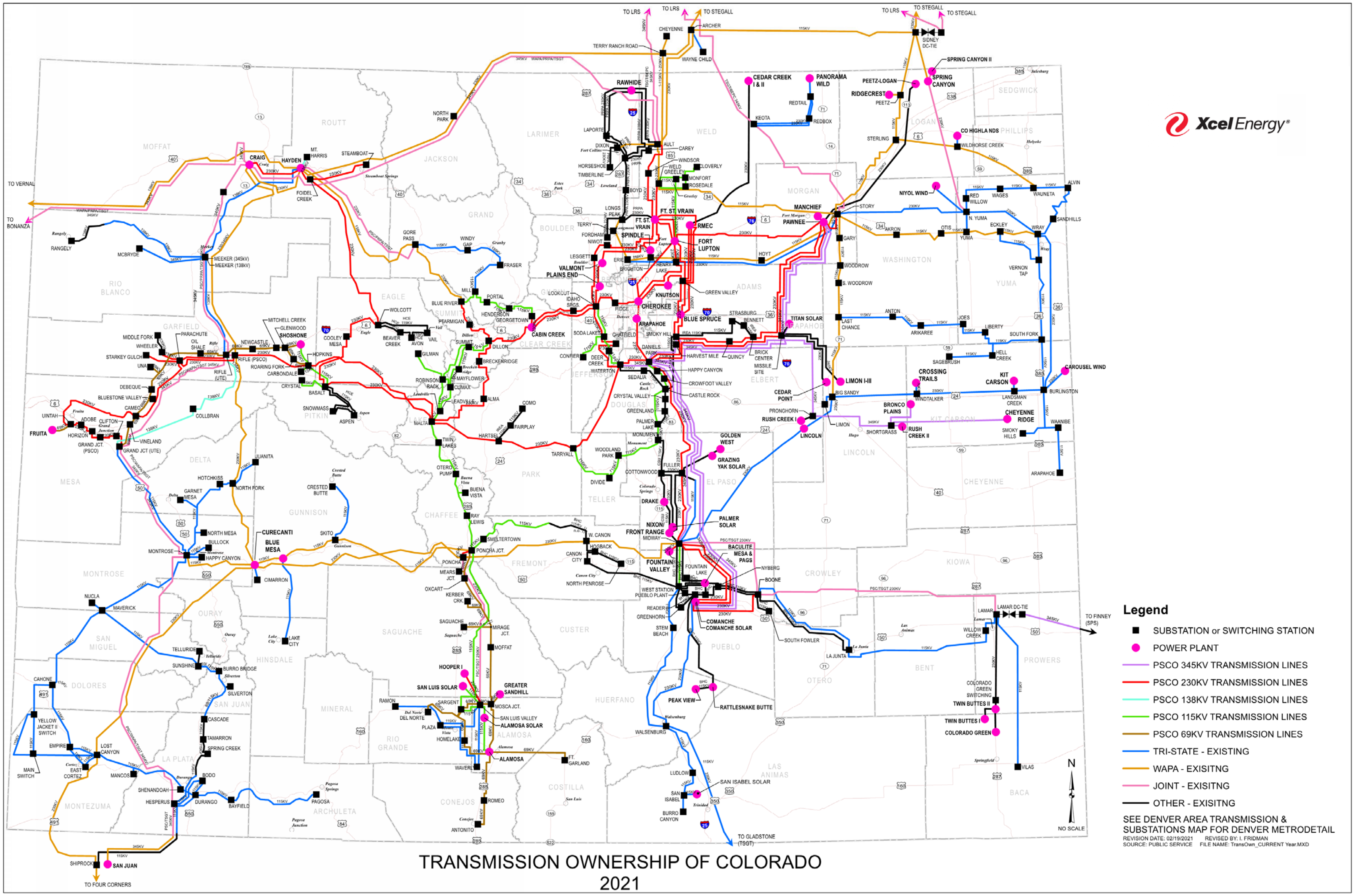


CCPG, which was formed in 1991, is a planning forum that cooperates with state and regional agencies to ensure a high degree of reliability in planning, development, and operation of the transmission system in the Rocky Mountain Region. Figure 4 shows the planning areas of the CCPG and other subgroups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

The Companies have a long history of coordinated transmission planning with each other and other TPs 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 before the adoption of Rule 3627.

As part of their Large Generator Interconnection Procedures, 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 (2022)



Internally, and through WestConnect and CCPG, each Company performs annual system assessments to verify compliance with reliability standards, determine related system improvements, and demonstrate adherence to the standards and criteria set forth by the 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 involving clean and renewable technologies;
- 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, the Companies consider proposed and enacted public policy initiatives likely to affect transmission planning. For purposes of this report, these initiatives are grouped into four broad categories: (1) policy initiatives related to decarbonizing the electricity sector; (2) policy initiatives such as beneficial electrification ("BE") expected to drive load growth; (3) policy initiatives expected to reduce demand for electricity; and (4) policy initiatives directly related to transmission infrastructure. Each of these categories is discussed below.

1. Public Policy Developments Related to Decarbonizing the Electricity Sector

A number of legislative developments from the past several years all target significant carbon reductions from the electricity sector. These developments, taken together, reflect the broader ongoing shift away from thermal generation toward renewable energy resources and will have significant impacts on the electric transmission system in Colorado. In particular, as additional decarbonization occurs, the Companies anticipate that transmission system improvements will focus on addressing the needs created by increasing penetrations of renewable energy resources on their systems.

a. Senate Bill 19-236 ("the PUC Sunset Bill")

Senate Bill 19-236 included numerous requirements for utilities and the CPUC to achieve an affordable, reliable, and clean electric system. Of these requirements, four are significant drivers for transmission development in Colorado: Clean Energy Plans ("CEPs"), the Cost of Carbon, the Colorado Transmission Coordination Act, and the requirement for Wholesale Electric Cooperatives to submit to the CPUC fully litigated electric resource plans ("ERPs").

i. Clean Energy Plans

Senate Bill 19-236 required retail utilities providing electric service to more than 500,000 customers to submit to the CPUC CEPs meeting certain criteria, including achieving an 80% reduction in carbon dioxide emissions from 2005 levels by 2030. *See* C.R.S. § 40-2-125.5. Public Service, which is subject to this mandatory requirement, filed a CEP in 2021. The legislation also provided that other retail electric utilities may "opt in" and voluntarily submit a CEP upon notification to the Commission. Black Hills has indicated that it plans to include a CEP in its next ERP filing under this "opt in" provision. Because Tri-State is not a retail electric utility, it did not submit a CEP with its

2020 ERP but has, nevertheless, included an 80% carbon dioxide emissions reduction as part of that filing.

In addition to the 2030 carbon dioxide emissions reduction requirement, CEP filings also must seek to reach a goal of 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 Colorado's Renewable Energy Standard ("RES") pursuant to C.R.S. § 40-2-124(1)(a). 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.

New transmission development associated with a CEP will be reviewed by the Commission under existing transmission planning and cost recovery processes, 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.

Under this framework, CEPs will present significant drivers for transmission planning. In particular, as the penetration of renewable energy resources increases, transmission expansion will be needed to ensure delivery of that energy to load centers. Interconnecting high levels of renewable energy resources to the transmission system also may require utilization of additional energy storage facilities to ensure that the transmission system remains reliable and resilient as high penetrations of renewables are achieved.

ii. Cost of Carbon

Senate Bill 19-236 additionally required 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: 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 the RES; electric demand-side management proceedings; and plans or applications for transportation electrification or other forms of BE. The cost of carbon dioxide emissions is based on the social cost of carbon dioxide developed by the federal government. SB 19-236 set this amount at $46 per short ton starting in 2020 and escalating thereafter. This amount was amended in HB 21-1238 to be $68 per short ton starting in 2020 and escalating 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 modeling. 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 and transmission 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.

iii. Colorado Transmission Coordination Act

The Colorado Transmission Coordination Act, C.R.S. § 40-2.3-101, *et seq.*, required the CPUC to open an investigatory proceeding on the potential costs and benefits of participation by Colorado's public electric utilities in a centralized market: specifically, an energy imbalance market, a regional transmission organization, a power pool, or a joint tariff. The statute directed the PUC to hold a public comment hearing to consider whether public electric utilities should participate in an energy imbalance market, RTO, power pool, or joint tariff. The CPUC held this hearing on June 24, 2021, and considered comments on a number of issues, including the results of a study performed by Siemens that evaluated the costs and benefits of various market structures as well as regional transmission authorities and/or independent system operators, energy imbalance markets, state or regional power pools, and joint transmission tariffs.

The statute further directed the Commission to issue a decision determining whether participation in an energy imbalance market, RTO, power pool, or joint tariff is in the public interest. The Commission issued such a decision on December 1, 2021[5], and found that participation in an organized market is in the public interest, but declined to endorse any particular market structure or provider.

Finally, the statute directed the Commission, on or before July 1, 2022, to take appropriate actions and conduct proceedings to pursue participation in an energy imbalance market, RTO, power pool, or joint tariff.

This legislation is separate from, but related to SB21-072, which, as discussed below, will with certain exceptions require the Companies to join an organized market by 2030.

An organized 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 ("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.

iv. Wholesale Electric Coops and Resource Planning

Senate Bill 19-236 additionally directed the Commission to promulgate new rules to require wholesale electric cooperatives to submit an application for approval of an integrated resource plan or an ERP. *See* C.R.S. § 40-2-134. The Commission

[5] See Decision No. C21-0755 in Proceeding No. 19M-0495E.

promulgated such rules in 2020 and Tri-State filed an ERP under the new rules in December 2020. Phase I of Tri-State's ERP is currently pending before the Commission.

Consistent with the scenarios discussed in its ERP, Tri-State expects to continue to interconnect new renewable energy facilities while retiring certain legacy facilities, and anticipates making transmission improvements as appropriate to accommodate these changes.

b. House Bill 19-1261

House Bill 19-1261 requires the Colorado Air Quality Control Commission ("AQCC") to promulgate rules and regulations for statewide greenhouse gas ("GHG") pollution abatement. *See* C.R.S. § 25-7-105. It also provides a "safe harbor" to any utility that has filed a CEP consistent with the requirements of Senate Bill 19-236, meaning that any complying utility will not be subject to both the provisions of SB19-236 and SB 19-261.

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 emissions, and whether program design could enhance the reliability of electric service.

For transmission planning, Colorado House Bill 19-1261 ("HB19-1261") and related implementing regulations create 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).

i. The Colorado Greenhouse Gas Pollution Reduction Roadmap

On January 14, 2021, Colorado released its Greenhouse Gas Pollution Reduction Roadmap ("Roadmap"). The Roadmap sets forth a number of steps intended to meet the state's climate targets of 26% by 2025, 50% by 2030, and 90% by 2050 from 2005 levels that were part of House Bill 19-1261. The Roadmap targets substantial GHG reductions from transportation, electricity generation, oil and gas development and fuel use in homes, business and industrial applications. In particular, it envisions that the state will: continue swift transition away from coal to renewable electricity, make deep reductions in methane pollution from oil and gas development, accelerate the shift to electric cars, trucks and buses, make changes to transportation planning and investment and land-use planning to encourage alternatives to driving, increase building efficiency and electrification, and reduce methane waste from landfills, wastewater and other sources.

For transmission planning, the Roadmap goals further indicate a need for additional transmission buildout and capacity to support increasing levels of renewable generation. They also indicate that additional transmission capacity will be needed to support load growth from BE and electric vehicle ("EV") adoption.

c. House Bill 21-1266 – Environmental Justice

House Bill 21-1266 is intended to address environmental justice issues, reduce GHG emissions across a number of sectors, and create a new source of funding for implementing climate rules. In particular, the bill directs the AQCC to adopt rules that pursue near-term reductions in GHG emissions, including reducing GHG emissions from electric utilities by at least 48% by 2025 and 80% by 2030, relative to 2005 levels. It also directs the Air Pollution Control Division of the Colorado Department of Public Health and the Environment to prepare an annual report that indicates whether GHG emission reduction requirements are being met and, if not, to develop and propose additional requirements to the AQCC.

For electric utilities that serve at least 50,000 Colorado retail customers, the bill requires them to either file a CEP (under the provisions of Colorado Senate Bill SB19-236 ("SB19-236")) or comply with AQCC rules that would require GHG emission reductions of at least 48% by 2025 and 80% by 2030, relative to 2005 levels. For wholesale generation and transmission electric cooperatives, the bill requires the filing of an ERP that will achieve at least an 80% reduction of GHG emissions by 2030, relative to 2005 levels.

Finally, the bill authorizes the AQCC to adopt a rule or program that provides for the use of a trading program, including a comprehensive and centralized accounting system to track emissions from sources that participate in the program.

HB 21-1266 will, like the other legislation discussed in this section, drive carbon reductions in the near and medium term, further indicating a need for additional transmission buildout to support the increasing levels of renewable energy generation expected to form the backbone of the various carbon emission-reduction plans filed by the Companies.

d. House Bill 18-1270 – Energy Storage Procurement Act

House Bill 18-1270 directs the Commission to develop a framework to incorporate energy storage systems in utility procurement and planning processes. 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. The bill finds that the benefits of storage 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.

e. Senate Bill 21-272 – Measures to Modernize the Public Utilities Commission

Senate Bill 21-272 expands the scope of Commission review for jurisdictional utilities in areas including retirement of generating facilities, the renewable energy standard, and resource planning. Senate Bill 21-272 also modernizes the operation of the Commission in areas including fixed utility fee funding, procedural schedules, and adjudication practices.

In particular, Section 3 is added to C.R.S. § 40-2-108, which requires the Commission to promulgate rules to "… provide equity, minimize impacts, and prioritize benefits to disproportionately impacted communities and address historical inequalities." This requirement covers Commission review of utility filings and adjudications. The Commission's consideration of transmission plans related to equity will inform the Companies' prioritization of equity in the development of transmission.

2. Public Policy Developments Expected to Drive Load Growth

Related to the carbon reduction policies discussed in the section above, a number of public policy developments target electrification of various parts of the economy such as heating and transportation. These developments will tend to drive load growth because services currently provided directly by fossil fuels instead will be electrified, creating additional demand for electricity. For example, as EV adoption increases, the Companies expect to see load growth associated with the charging requirements for these vehicles.

In general, the Companies expect that load growth associated with electrification will tend to create additional transmission requirements in Colorado. Some load growth driven by these electrification policies may be offset, however, by policy developments related to distributed generation and demand-side management, both of which may reduce transmission system requirements in some cases.

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

Senate Bill 19-077, as codified in C.R.S. §§ 40-1-103.3, 40-3-116, and 40-5-107, supports widespread electrification of transportation in electric utility service territories.

In May 2020, each jurisdictional utility – Public Service and Black Hills – filed timely applications with the Commission for approval of 2021-2023 Transportation Electrification Plans (“TEPs”). The plans were a statutory mandate in Senate Bill 19-077. The plans were litigated and approved by Commission decisions, with modifications.

The regulated activities in each plan support transportation electrification. The key highlights are as follows:

EV adoption with rebates. Both utilities will provide TEP rebates to customers. The rebates will be recorded and amortized as regulated assets. Public Service will provide rebates for vehicles and charging equipment, also referred to as Electric Vehicle Supply Equipment (“EVSE”). Public Service will provide point-of-sale rebates for vehicles purchased or leased by income-qualified customers. The rebates are to be used in place of existing state EV tax credits. Public Service will provide EVSE rebates to residential customers for a 240-volt electrical circuit installation to support a Level 2 charger; income-qualified customers will receive a higher dollar amount. Other rebates are available from Public Service for EVSE in fleet, workplace, or community hub locations where such locations meet income qualifications or are located within high emissions communities. Additionally, Public Service will provide rebates to multifamily property developers adding extra, qualifying EV parking spots to their sites during the design phase.

Black Hills will provide EVSE rebates at two charging levels. Rebates for Level 2 EV chargers purchased by customers with higher rebate amounts awarded for income-qualified customers. Rebates for direct-current fast chargers (“DCFC”) Level 3 charging ports also will be awarded with the dollar amount of such rebates tiered according to equipment charging speed. Recipients for DCFC Level 3 rebates must demonstrate a minimum level of project readiness before the award. Additionally, Black Hills will provide rebates for EV purchases within a budget limit. The upfront rebates for EV purchases are $5,500 for new vehicle purchases and $3,000 for used vehicles and the MSRP of any vehicle purchased is capped at $50,000. As with Public Service, the rebates are to be used in place of existing state EV tax credits.

EV charging with incentive rates. Both utilities will provide tariffed EV rates by customer class that encourage off-peak charging for grid optimization. Public Service rates have a managed-charging requirement for the customer (a charging optimization program). Black Hills will require residential customers to have time-differentiated rates if such customers receive an EVSE rebate. The residential customers may opt out of such rate design after a minimum 12 months of participation, with income-qualified customers allowed to opt out after one month of participation. For the needs of both large commercial fleet charging and public charging at DCFC stations, Black Hills will design an additional time-differentiated rate.

EV infrastructure buildout. Public Service will offer to install, own, and maintain Level 2 chargers at residential customer premises through a monthly charge on the customer's bill. For fleet and workplace charging, Public Service will provide utility-owned electric vehicle supply infrastructure ("EVSI"). This is a benefit and significant cost savings for non-residential customers who need scale charging. For public charging, Public Service will provide 20 to 25 DCFCs in underserved areas throughout the service territory. A siting analysis will identify these areas. The DCFCs will be ratepayer-funded, utility-owned assets. For community charging hubs, such as cities or neighborhood associations, Public Service will install, own, and maintain EVSI.

Black Hills will designate as permanent service new extensions of distribution line to serve EV charging stations. Unlike indeterminate or temporary service, a customer with permanent service will be eligible for refunds of their construction charges when certain performance requirements are met. Black Hills is not at this time proposing to own EVSE, such as DCFC.

EV awareness. Public Service will host research, innovation, and partnerships in its Partnerships, Research, and Innovation Portfolio. Potential areas of interest for the portfolio are shared mobility programs such as e-bikes and e-scooters, reducing DCFC charging costs with energy storage dispatch, optimized fleet operations, enhanced grid planning by detecting EV charging with Advanced Metering Infrastructure ("AMI") equipment, and electrifying school buses.

Black Hills will engage with local automobile dealerships and, through partnerships, will provide a prioritized dealership list to its customers. Black Hills will implement a grassroots campaign with employees. Black Hills will host mass-transit stakeholder meetings to prepare for future e-bus pilot programs and mass-transit infrastructure rebates.

Finally, as the EV market evolves and matures, each Company will provide stakeholders with a 60/90-day notice of changes to the suite of EV charging programs. A 60-day notice will be for new pilots or to change technical assumptions or eligibility requirements for existing programs. A 90-day notice will be for program cancellations.

EV equitable participation. Income-qualified customers and emissions-burdened communities will receive favorable treatment in each TEP. Public Service will have a 15% spending floor in its TEP budget for EV programs targeted to these segments. Black Hills will reserve 15% of total plan budget for income-qualified customers and higher emissions-impacted communities. Both Public Service and Black Hills may have an Equity Performance Incentive Metric ("PIM") after a later, stakeholder engagement process. For example, a PIM may be based on the number of charging ports installed for income-qualified and targeted communities.

The implementation of each TEP, specifically the deployment of EVs and charging infrastructure, will present load growth for transmission planning. The load growth from such plans will be managed and balanced. System safety and reliability will be managed through interoperability and technical standards. These standards will be established through a TEP stakeholder process. Grid use will be balanced as the

TEPs encourage flexible charging behavior through off-peak incentive rates and charging optimization requirements.

b. House Bill 21-1238

House Bill 21-1238 amends and adds numerous provisions in the statutory requirements applicable to gas utility demand-side management ("DSM") programs.

The provisions update gas DSM program evaluations. Accounting and methods for determining cost-effectiveness of such programs are updated. Specifically, the calculation of future benefits from reduced gas consumption must separately account for avoided GHG emissions – both carbon dioxide and methane.

In 2022 and every four years thereafter, certain gas distribution utilities are required to file DSM Strategic Issues applications. The applications will develop energy savings targets for utilities, develop an estimated DSM budget, and include the potential for reduced GHG emissions.

The statute provides that gas DSM program plans may be combined with electric DSM program plans, beneficial electrification plans, or other plans that reduce energy consumption or GHG emissions. Other plans may include weatherization and insulation programs and potential behind-the-meter thermal renewable resources.

Electrification of buildings may emerge directly or indirectly from modernized gas DSM programs. The provisions of House Bill 21-1238 therefore represent potential electric load growth for transmission planning.

c. Senate Bill 21-246

Senate Bill 21-246 adds provisions in the statutory requirements to require investor-owned electric utilities to file a beneficial electrification plan application. Municipally owned electric utilities, cooperative electric associations, and wholesale electric cooperatives are encouraged to develop BE plans. BE means converting a customer's end use of energy from a nonelectric fuel to a high-efficiency electric source or avoiding the use of nonelectric fuel sources in new construction or industrial applications.

On or before July 1, 2022, and thereafter every three years, a BE plan must be filed by investor-owned electric utilities. The plan may be combined with DSM strategic issues or transportation electrification plans. When determining the cost, benefit, or net present value of any plan or proposal, the social costs of carbon dioxide and methane emissions must be considered. Specifically, these social costs must be applied to the non-energy benefits of BE programs. At least 20 percent of the total BE program funding must be targeted for low-income households or disproportionately impacted communities.

Senate Bill 21-246 provides incentives for electric utilities to implement a BE plan. These include an incentive rate of return on the investments, accelerated depreciation, a sharing of net economic benefits, and rider for cost recovery. Investor-owned gas utilities may file BE plans.

Longer term, beginning April 1, 2024, and every six years thereafter, an investor-owned electric utility shall file a BE strategic issues application. A 10-year BE target shall be proposed and objective criteria for measuring attainment of the target.

BE presents incremental load for transmission planning. Utilities must demonstrate that the incremental load attributable to beneficial electrification will be served with generation reasonably expected to have a carbon intensity no higher than the average carbon intensity for all generation in the utility's portfolio.

d. Senate Bill 21-264

Senate Bill 21-264 adds requirements in the statutory requirements for gas distribution utilities to file plans to reduce carbon dioxide intensity in the sector ("clean heat plans"). The requirement is for gas distribution utilities with more than 90,000 retail customers.

The GHG reduction target in Senate Bill 21-264 is 4% by 2025 and 22% by 2030, both from 2015 baseline levels. The largest investor-owned utility must file clean heat plans with the Commission by August 1, 2023, and all other utilities by January 1, 2024. A municipal gas distribution utility with more than 90,000 customers must file a clean heat plan with CDPHE by August 1, 2023. Clean heat plans will be filed every four years thereafter, with a minimum five-year planning horizon.

Clean heat resources for these plans may substitute natural gas with other sources of recovered methane (e.g., landfills or coal mines), blue or green hydrogen, methane leak detection from the utility's supply chain, BE, and energy efficiency.

The clean heat plan must demonstrate a reasonable cost mix of clean heat resources to meet the clean heat targets. The social cost of carbon and the social cost of methane must be included in the cost evaluations. Any new delivery infrastructure avoided as a result of the clean heat plans will be included favorably in the cost evaluation. The reductions in clean heat plans must fall within a 2.5% cost cap, but municipal utilities and utilities with fewer than 250,000 customers will have a 2.0% cost cap. As the sector adopts BE, clean heat plans present potential electric load growth for transmission planning.

e. Senate Bill 21-260 – Sustainability of the Transportation System

Senate Bill 21-260 creates new sources of dedicated funding and new state enterprises intended to enable the planning, funding, development, construction, maintenance, and supervision of a sustainable transportation system by, among other things, developing the modern infrastructure needed to support the widespread adoption of electric motor vehicles. In particular, it creates a "clean transit enterprise" within the Colorado Department of Transportation for the purpose of supporting clean public transit through electrification planning efforts, facility upgrades, fleet motor vehicle replacement, and construction and development of associated electric motor vehicle charging and fueling infrastructure.

This additional funding is likely to further increase adoption of EVs in Colorado, resulting in additional demand for electricity associated with EV charging. As this EV-related demand increases, additional capacity on the transmission system may be necessary to accommodate the increased charging demand.

3. Public Policy Developments Related to Distributed Generation and Energy Efficiency Expected to Reduce Demand for Electricity

a. Senate Bill 21-261

Senate Bill 21-261 reforms the governing law for customer-sited renewable energy generation facilities (retail renewable distributed generation). The reforms will scale up retail renewable distributed generation. Some key highlights are described here.

The allowable capacity increases from 120% of the customer's historical annual usage to 200% of the customer's reasonably expected average annual usage as a total of all properties owned or leased by the customer. The size of eligible on-site renewable energy installations increases from 500 kW to 1 megawatt, while off-site is limited to 500 kW for a single meter to 300 kW per meter for multimeter installations.

A new off-site net-meter program is authorized, governing installations of renewable facilities located at noncontiguous property owned or leased by a customer within a utility's service territory.

Senate Bill 21-261 directs the Commission to adopt rules for landlords and tenants in multiunit buildings to share in the costs and benefits of installing new distributed generation facilities.

The Commission is directed to adopt rules concerning the aggregation and interconnection of retail distributed generation, including the allocation of net metering credits among customers on different rate schedules. A single distributed generation facility on a multiunit property may allocate its credit to common areas or to individually metered accounts. Master metered operators may allocate excess net energy metering credits to any meter.

Renewable energy storage is designated an eligible energy resource under the state's Renewable Energy Standard where such facility stores energy produced only by renewable energy resources.

The qualifying retail utility may have optional programs and tariffs for dispatchable renewable distributed generation and storage.

Meter collar adapters will be allowed for customer ownership and use. This is a device installed between the electric meter and the meter socket box. The device allows electrical isolation of the customer's site for energy backup purposes. The qualifying retail utility must adopt standards for the approval of customer-owned meter collar adapters.

Senate Bill 21-261 increases deployment of customer-sited renewable distributed energy resources, expands the allowable capacity, allows for off-site participation, and enables more local control. Electric vehicles will have more locally produced power options for charging. Given these provisions, Senate Bill 21-261 may cause a load growth reduction for the incumbent utility electric, as well as considerations related to siting of distributed generation, for transmission planning purposes.

b. House Bill 20-1155

House Bill 20-1155 adds to existing law that requires a home builder to offer certain buyer options for a new home: a solar panel or solar thermal system, pre-wiring or pre-plumb, or a chase or conduit to wire or plumb the home for these systems in the future. The legislation provides further options for a newly constructed residence in support of EVs: an EV charging system, upgrades of wiring to accommodate future installation of EV charging system, or a 208- to 240-volt alternating current plug-in accessible to a motor vehicle parking area. It also adds the option for efficient electric heating and water heating systems, such as heat pumps, and causes the building to provide pricing, energy efficiency, and utility bill information for each option available.

Finally, the Colorado Energy Office must provide basic consumer education about leased and purchased solar installations.

This bill continues the importance in transmission planning to consider beneficial electrification and its related load growth, as well as increased deployments of distributed generation.

c. Senate Bill 20-124

Senate Bill 20-124 adds guidelines for applications from the public school capital construction assistance funds. Such guidelines require consultation with the local electric utility on energy efficiency, beneficial electrification, and renewable distributed generation. The effect is similar to the previously described bills.

d. Senate Bill 18-009 – Energy Storage

Senate Bill 18-009 prevents the implementation of unnecessary restrictions or regulations and without unfair or discriminatory rates or fees for any customer that installs, interconnects, and uses an energy storage system on their property.

4. Senate Bill 21-072 – Transmission Infrastructure Modernization

Senate Bill 21-072 directly addresses transmission planning in Colorado through a number of provisions.

The bill sets forth deadlines and conditions under which an electric utility that owns and controls transmission facilities must join an organized wholesale market ("OWM"). In particular, the bill requires each of the Companies to join such a market by 2030 unless the CPUC determines that: (1) the transmission utility has made all reasonable efforts to comply with the requirement, but there is no viable and available OWM that the transmission utility can join by January 1, 2030; and (2) that requiring the transmission utility to join an OWM is not in the public interest based on the Commission's evaluation of appropriate factors, including whether the OWM has established policies regarding tracking and reporting of emissions with a system to attribute emissions to transmission owners, promoting load flexibility and demand-side resources, promoting the integration of clean energy resources, and reducing the costs and inefficiencies of transactions between balancing areas and between market constructs, if any. The requirement to join an organized wholesale market presents the potential for significant changes to the manner in which transmission is planned and developed in Colorado. Until such time as the Companies join these markets, the specific impacts on transmission will not be known.

The bill also creates the "Colorado Electric Transmission Authority" as an independent special purpose authority. The Colorado Electric Transmission Authority is authorized to select a qualified transmission operator to finance, plan, acquire, maintain, and operate eligible electric transmission and interconnected storage facilities and has the power to issue revenue bonds, identify and establish intrastate electric transmission corridors, coordinate with other entities to establish interstate electric transmission corridors, exercise the power of eminent domain to acquire eligible facilities, and collect payments of reasonable rates, fees, interest, or other charges from persons using eligible facilities. This provision of the bill may encourage additional transmission development, and it will foster additional coordination among transmission developers in Colorado.

C. Emerging Issues[6]

The Companies' 2020 10-Year Transmission Plan identified four emerging issues: Wildfire Risk Mitigation, Energy Storage and Non-Wires Alternatives, Distributed Energy Resources ("DER"), and Grid Resiliency with Inverter-Based Resources. Each of these continue to be key considerations for the Companies' transmission planning purposes; however, they are no longer "emerging" issues – they are present and ongoing issues.

- The devastating 2021 wildfires in Colorado, California, Oregon, Washington, and other western states have demonstrated the continuing risks to the electric grid as a result of such incidents. Wildfire mitigation and grid resiliency efforts continue to be priorities for the Companies.

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[6] On Nov. 30, 2021, the Utilities met with Commission Staff and UCA Staff to discuss, among other topics, the subjects the Companies intended to address as Emerging Issues.

- The potential deployment of energy storage is now routinely considered in the Companies' resource and transmission planning, and the Companies are now required to consider Non-Wires Alternatives and Advanced Transmission Technologies in their Ten-Year Transmission Plans. (Proceeding No. 20M-0008E, Decision No. R21-0073, ¶ 45).
- Driven by economic and sustainability concerns, public interest in and actual deployment of customer-sited, behind-the-meter DERs continues to grow. The enactment of SB21-261 (C.R.S. § 40-2-124(1)(a)(VIII)) and the resulting increase in the permissible capacity of retail DERs to as much as 200% of the customer's reasonably expected average annual consumption is likely to spur further growth. While DERs often are considered to be a distribution issue, the Companies also must consider the "upstream" effects on the transmission system. Furthermore, increased interest in pairing energy storage with DERs has resulted in new reliability concerns and is likely to lead to other as-yet unidentified challenges. Recognizing these concerns and challenges, NERC recently issued a new Reliability Guideline related to energy storage and DERs - *Performance, Modeling, and Simulations of BPS-Connected Battery Energy Storage Systems and Hybrid Power Plants* (March 2021).
- Finally, grid resiliency continues to be an overarching consideration for the Companies. The growing deployment of inverter-based renewable energy resources, the current and planned retirement of baseload thermal generation resources driven by Colorado's and other states' decarbonization plans, and recent extreme weather events in Colorado and elsewhere all emphasize the importance of planning for grid resiliency.

These and other emerging issues identified in previous 10-Year Plans are now routine considerations in the Companies' transmission planning. While there are likely other topics that could be identified as emerging issues for purposes of transmission planning, the Companies have focused on the following issues for discussion in the 2022 10-Year Transmission Plan.

1. Organized Markets

Since the Companies' 2020 10-Year Transmission Plan, the Colorado Transmission Coordination Act (C.R.S. § 40-2.3-101, *et seq.*) became law and requires the Commission to determine by Dec. 1, 2021, whether Colorado electric utilities' participation in an energy imbalance market ("EIM"), RTO, power pool, or joint tariff is in the public interest. Through Decision No. C21-0755 in Proceeding No. 19M-0495E, the Commission concluded that participation is in the public interest and directed Commission Staff and electric utilities to begin taking appropriate actions to pursue participation in an EIM, RTO, power pool, or joint tariff. As discussed previously, on December 1, 2021, the Commission issued its decision wherein it concluded that such participation is in the public interest.

Subsequently, Colorado Senate Bill 21-072 became law and requires, in part (C.R.S. § 40-5-108), that Colorado transmission utilities[7] join an OWM on or before Jan. 1, 2030. As discussed above, the Commission may waive this requirement upon application by a transmission utility and a finding that the utility has made all reasonable efforts to comply with the requirement, but there is no viable OWM the utility can join by Jan. 1, 2030, and the Commission has determined that requiring the utility to join an OWM is not in the public interest. Consistent with the emerging issues discussed by the Companies in their 2020 10-Year Transmission Plan, in enacting SB21-072 the General Assembly found that Colorado transmission utilities' participation in an OWM "will assist transmission utilities . . . in ensuring the resilience of the electric grid and its resistance to both natural disasters and intentional attacks." C.R.S. § 40-5-108(2)(c).

While organized markets in Colorado and the West have been discussed for years and, as such, this is not a new issue, what is "emerging" is the fact that steps are being taken by the Commission and Colorado electric utilities toward participation in an organized market. The Companies, individually or through the Balancing Authorities in which they have load, are either participating in or proceeding toward participation in the

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[7] Each of the Companies meets the definition of a "transmission utility." (*See* C.R.S. § 40-5-108(1)(b))

Southwest Power Pool's ("SPP") Western Energy Imbalance Service ("WEIS"). In February 2021, Tri-State and certain Colorado non-jurisdictional utilities were inaugural participants in SPP's WEIS. Most recently, on January 25, 2022, Public Service and Black Hills (along with PRPA) announced plans to join the WEIS operated by SPP. Transmission benefits from joining the WEIS may include improved efficiencies in operations of the system that can reduce energy costs. Public Service and Black Hills expect to begin participation in the WEIS in April 2023. At this point, they do not foresee the WEIS impacting Public Service's or Black Hills' 10- and 20-year scenarios included in this filing, though they will continue to evaluate likely and potential transmission impacts of the WEIS, and integrate those into transmission planning and analysis on a going-forward basis. These will be reflected in future Rule 3627 filings along with other relevant and/or appropriate filings with the Commission.

Furthermore, Tri-State and certain Colorado non-jurisdictional utilities are actively evaluating full RTO membership in SPP. Public Service, Black Hills and 12 other western US electric utilities are exploring regional market solutions through a newly formed group, Western Markets Exploratory Group ("WMEG"). As some form of organized market participation by one or more Colorado electric utilities, including the Companies, appears increasingly likely – either as a result of the utility's own decisions or in compliance with legislative and regulatory requirements, the practical effect of such participation on Colorado transmission planning will become a more tangible and imminent consideration.

2. Extreme Weather Events

From an electricity standpoint, Colorado is a summer peaking state driven by warm temperatures and cooling demands. Colorado electric utilities have long planned to meet this peak demand through adequate generation resources and reliable transmission. July 2021 made this issue clear, as it was globally the hottest month on record and the eleventh hottest month on record for Colorado. Extreme summer temperatures are driving increased electricity demand at the same time they create increased risk of wildfires that threaten the electric grid. However, at the other end of the spectrum, the extreme weather events of February 2021 showed that Colorado utilities also must plan to meet extraordinarily cold temperatures and their effects on both demand and the generation and transmission systems' abilities to meet that demand. Such extreme and unpredictable summer and winter weather events present new considerations for the Companies' transmission planning.

3. Community Choice Aggregation and Non-Regulated Wholesale Power Suppliers

As evidenced by various legislation and initiatives around the country, and by the Commission's study required by Colorado Senate Bill 21-1269 (Proceeding No. 22I-0027E), there is nascent interest in the concept of community choice aggregation ("CCA"), i.e., the ability to procure a community's electricity from a supplier other than the electric utility certificated to serve that community. While CCA is considered by some to be a means for a community to meet its clean energy goals, its deployment has consequences for effective transmission planning in Colorado. The Companies, and non-regulated utilities as well, plan their transmission systems to meet the needs of the communities in their service territories that they are obligated to serve. If those communities can elect at any time to receive their wholesale power supply from other providers, this makes it difficult for utilities to not only plan the necessary transmission system but also to identify and justify investments in transmission system improvements.

Closely related to CCA is the effect of non-regulated wholesale power suppliers. Whether they are simply power marketers or actually own their own generation resources, these non-regulated power suppliers have one thing in common – they rely upon access to and use of electric utilities' transmission systems to deliver their wholesale power to their customers. These power suppliers are not subject to the Commission's transmission planning rules but create, or have the potential to create, similar demands on the Colorado transmission system. Whether in connection with CCA or as a result of bilateral supply contracts with municipal utilities or distribution cooperatives, the effect of these suppliers' use of the transmission system is an additional issue for transmission planning purposes.

4. DC Fast Chargers

Electric vehicle adoption (charging demand) will impact grid needs. The grid impact will depend on the extent that charging infrastructure is installed at higher power levels – specifically, 50 kW, 150 kW, and 350 kW per charging port. These are known as DC Fast Chargers within the category of EVSE.

Public and private DC Fast Chargers will locate on transportation corridors and co-locate at retail, commercial, and industrial premises.

An August 2021 technical paper[8], co-authored by the National Renewable Energy Laboratory and Latent Engineering, provided modeling results of power demand where DC Fast Chargers are co-located at a big-box retail store – specifically, a supermarket.

The modeling results yielded two conclusions:

1) There were no changes to the big-box building demand profile where the EV charging station had two, 50 kW ports and low utilization.
2) There was a 250% increase to the big-box building demand profile where the EV station had six, 350 kW ports and all vehicles charge at once. The EV charging station alone required up to 2.1 MW. It exceeded all components of the building where such components included AC cooling, lights, refrigeration, heating, and plug loads.

The parameters for determining EV charging station demand are the number of ports per charging station, the utilization per port, and the kW capacity of each port.

Mitigating factors to a higher combined demand profile (big-box building and EV charging together) may be the extent of onsite PV generation, flexible loads within the

[8] Impact of EV charging on the power demand of retail buildings. Elsevier August 2021. https://www.sciencedirect.com/science/article/pii/S2666792421000548

building envelope, energy storage capabilities, and controlled EV charging influenced by utility time-differentiated tariff rates.

As significantly higher peak loads develop, specifically with extreme fast charging at 350 kW or higher ports, incremental demand growth for transmission planning is projected to occur.

D. Alternative Technologies

The Companies considered alternative technologies, such as non-wires alternatives and advanced transmission technologies, as opposed to conventional transmission projects in the development of the 10-Year Transmission Plan. The following types of technologies are considered: (1) High Voltage Direct Current ("HVDC"), including underground installations within existing railroad rights-of-way ("ROW"); (2) dynamic line ratings ("DLR"); (3) transmission system topology optimization; (4) power flow control technologies; (5) energy storage, and (6) specialized conductors. In transmission planning, the specific technologies are considered when appropriate based on the applications described below.

1. High Voltage Direct Current

An HVDC system utilizes direct current ("DC"), rather than standard alternating current ("AC"), for bulk transmission of electrical power. HVDC becomes cost competitive at long distances (generally 200-plus miles), and therefore is not considered except for very long transmission lines or for asynchronous connection between the Eastern, Western, and/or Texas Interconnections. Examples of HVDC include the DC Ties (such as Lamar (210 MW) between the Eastern and Western Interconnection, and the Pacific DC Intertie (3100 MW) between the Pacific Northwest and Los Angeles.

2. Dynamic Line Ratings

DLR refers to the adoption of transmission line ratings based upon *real-time* monitoring of equipment and/or weather conditions (ambient temperature, wind speed, wind direction, etc.) in the operation of the transmission system. This contrasts with transmission planning, which is performed with static line ratings based upon generally conservative *future* weather conditions. As such, DLR is an operational consideration and cannot be evaluated in the context of the 10-Year Transmission Plan.

On December 16, 2021, the FERC issued Order No. 881 – Managing Transmission Line Ratings in which it required, among other things, that public utility transmission providers implement ambient-adjusted ratings on transmission lines as part of the operation of the transmission system and provide on their Open Access Same-Time Information System ("OASIS") site transmission line ratings and rating methodologies. While the Order could have implications for the Companies' use of DLR, FERC declined to mandate DLR implementation at this time, but will further explore it in a new docket.

3. Transmission System Topology Optimization

Topology optimization is transmission system reconfiguration, through automatic switching of circuit breakers open or close, to reroute power off constrained transmission facilities. To an extent, topology optimization already is performed operationally by system operators. System operators will create open points on the transmission system based on near-term studies to maintain transmission system reliability during planned and unplanned outages.

In transmission planning, topology optimization involves consideration of creating normally open points on the transmission system, or through the development of Remedial Action Schemes ("RAS"), which can automatically reconfigure the transmission system. Normally open points on the transmission system are generally considered when system performance can be improved without reducing reliability to customers. RAS can automatically create open points on the transmission system based on system conditions. However, RAS have NERC compliance requirements due to potential reliability and security risks, resulting in a measured and pragmatic approach to their implementation.

4. Power Flow Control Technologies

Power flow control technologies help control flow through a given path through automatic or manual operation. Power flow control technologies include phase-angle regulating devices (such as phase-shifting transformers) and Flexible Alternating Current Transmission Systems ("FACTS") devices. FACTS devices include various types of series or shunt compensations to control voltage or power flow on the transmission system. A brief description of each type of power flow control technology is provided below.

Phase Angle Regulator ("PAR") or Phase-Shifting Transformer ("PST") adjust the power angle (δ) to "push" or "pull" power flow on the transmission system. PARs and PSTs are considered when there is a need to reduce/remove thermal overloads under contingency conditions, force contractual/scheduled power flows, and/or mitigate loop or unscheduled flows. The only PSTs connected to the Colorado transmission system are located along the Colorado-New Mexico border.

FACTS (shunt compensation) devices are used to control voltages on the transmission system and includes shunt reactors, shunt capacitors, Static Synchronous Compensators ("STATCOM"), and Static VAR Compensators ("SVC"). Shunt reactors depress system voltages, typically in response to high voltages caused by the Ferranti Effect and/or underground cable. Shunt capacitors support/increase voltages, typically in response to depressed voltages caused by heavy system loading, or to improve load power factor. STATCOMs are power electronics voltage-source converters that can act as a source or sink of reactive power, thereby supporting or depressing system voltages as needed. STATCOMs provide dynamic voltage support and improve voltage stability on the transmissions system. SVCs are dynamically controllable parallel reactance that can act as a source or sink of reactive power, thereby supporting or depressing system voltages. SVCs provide dynamic voltage support and improve voltage stability on the transmissions system. FACTS (shunt compensation) devices are considered when static or dynamic voltage performance violations arise in transmission planning.

FACTS (series compensation) devices are used to control/influence power flow on the transmission system and includes series reactors, series (fixed and variable) capacitors, Static Synchronous Series Compensators ("SSSC"), and Distributed Series Compensator ("DSC"). Series reactors increase the impedance (+jX) of a transmission path and are used to reduce flows under outage conditions or reduce/limit short circuit current. Series (fixed/variable) capacitors decrease the impedance (-jX) of a transmission path and are used to improve angular/voltage stability and provide better power sharing between parallel paths. Series variable capacitors are effective at improving damping of inter-area oscillation modes. SSSCs inject sinusoidal voltages in series with the line, which acts as an inductive (+jX) or capacitive (-jX) reactance, thereby "pushing" or "pulling" power flow. SSSCs provide dynamic series compensation and can improve voltage stability on the transmissions system. DSCs are the single-phase model of a SSSC and have the same functionality. FACTS (series compensation) devices are considered when there is a need to reduce/remove thermal overloads under outage conditions, improve angular/voltage stability, or improving damping of inter-area oscillation modes.

The Unified Power Flow Controller ("UPFC") is a FACTS device that includes both series and shunt compensation. UPFC is a combination of a STATCOM and a SSSC coupled via a common DC voltage link. A UPFC is only considered when a unique combination of voltage and thermal performance violations occur in transmission planning.

5. Energy Storage

Energy storage technologies are a means to capture and store energy for use on the transmission system. Energy storage technologies can help influence flow through a given path through charging and discharging cycles, enable load management, store excess resources, and/or provide voltage support. Charging cycles can provide short term reduction in curtailment. Energy storage is typically installed in conjunction with wind and/or solar generation facilities.

a. Specialized Conductors

Specialized conductors include a wide range of conductors outside industry-standard Aluminum Conductor Steel Reinformed ("ACSR") and Aluminum Conductor Steel Supported ("ACSS") conductors. Specialized conductors include composite core conductors, which are capable of higher operating temperatures (up to 200 degrees Celsius) with reduced sag. All conductors are considered in transmission planning, but a focus of planning studies is to identify transmission endpoints and/or ampacity requirements for new or existing transmission. Specific conductors to meet the ampacity needs are identified and selected as part of detailed engineering of transmission projects, rather than at the transmission planning stage.

III. Company Plan Narratives

A. Black Hills 10-Year Plan Overview

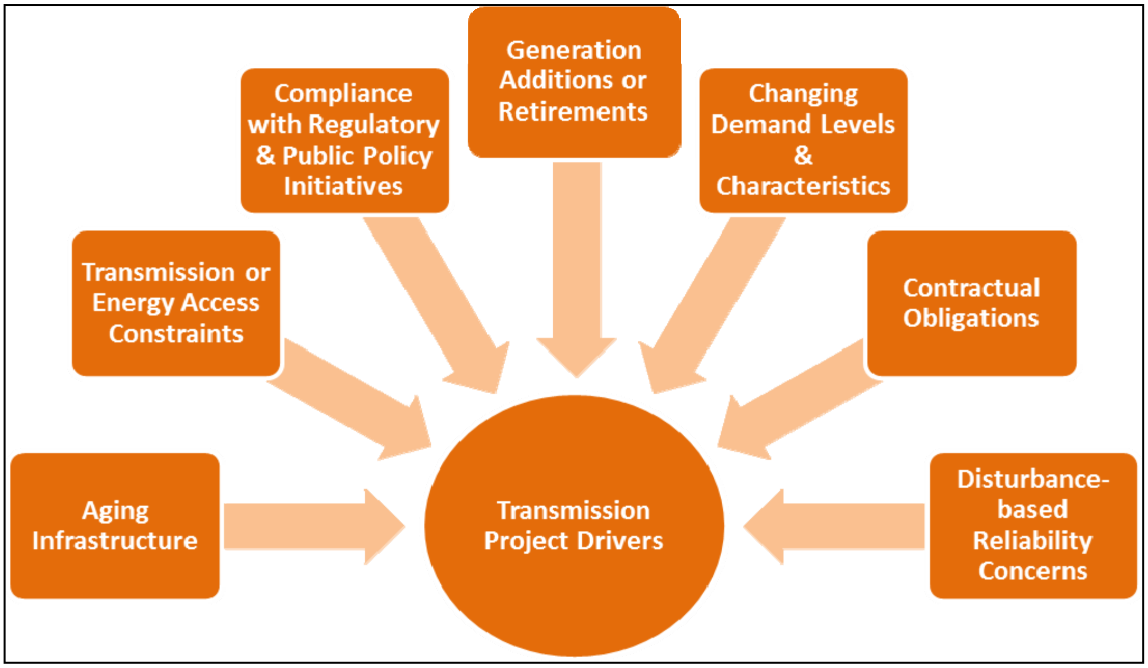
1. Black Hills Service Territory

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)

In 2023, a 200 MW utility-scale solar energy project, Renewable Advantage, is expected to begin commercial operations in Black Hills' electric service territory. The project will be located in Pueblo County. The project was awarded as a result of a competitive solicitation conducted by Black Hills Energy. Authority for the competitive solicitation was granted in Commission Decision R20-0647.

The developer and owner, 174 Power Global LLC, entered into a 15-year power purchase agreement on February 19, 2021, to sell all of the energy output to Black Hills Energy. Upon the startup of Renewable Advantage, 51 percent of the Black Hills Energy generation mix in Colorado will come from renewable sources, leading to a 71 percent reduction in GHG emissions by 2024.

Black Hills Energy is proceeding with various permitting, landowner rights-of-way, and construction activities for new transmission facilities to deliver energy output from Renewable Advantage to load centers. Specifically, three new substations will be constructed (Pueblo West, North Penrose, Canon City) and a 39-mile single-circuit 115-kV transmission line will be installed from the Company's existing West Substation, through Pueblo West, to Cañon City. The transmission facilities will improve reliability and support continued growth in Pueblo and Fremont counties. The transmission facilities are further described in Section B below, including a reference to the Commission decision granting Black Hills authority to proceed with construction.

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 2022 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 2022 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 2020 10-Year Plan, Black Hills has completed three projects: Desert Cove-Midway 115 kV line rebuild, Airport Memorial – Nyberg 115 kV line rebuild, and Boone – La Junta 115 kV line rebuild. Black Hills identified eight planned projects within the upcoming 10-year planning horizon that represent $76.9 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 2022 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
West Station – Hogback Transmission Line[9]	1/2023	$24.00	Not required. Decision No. C17-0539
115/69 kV Hogback Ranch Substation Build	1/2022	$9.90	Not required. Decision No. C17-0539
115kV North Penrose Distribution Substation	1/2022	$6.7	Not required. Decision No. C20-0477

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 – Hogback 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 – Hogback 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

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

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 2022 SB07-100 Study Report included in Appendix N 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

Three 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 2022 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
115 kV Rodrigues Substation	6/2023	$7	Not required Decision No. C19-638
115kV Pueblo West Distribution Substation	1/2023	$5.4	Not required Decision No. C20-0477
115kV West Station-Greenhorn Line Rebuild	1/2023	$7	Not required Decision C18-843

The 115 kV Rodrigues Substation project was determined by the planning team to be a way to rectify growth concerns for the increasing demand in Colorado. Rodrigues 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 still is in land negotiation phases; therefore, the total project cost is TBD.

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.

Rocky Ford area

Two 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 2022 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
South Fowler Substation	1/2022	$5.10	Not required; Decision No. C19-0638
Boone – South Fowler 69/115kV Conversion	1/2022	$11.8	Not required; Decision No. C19-0638

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 2022 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

3. Black Hills Alternative Technologies

Black Hills has included alternative technologies such as the ones mentioned earlier in this filing for all new projects. Any new projects submitted for ruling on the need for a Certificate of Public Convenience and Necessity (“CPCN”) will include narratives on which alternative technologies were considered and why they were or were not chosen. For purposes of this filing, Black Hills does not have any new projects to discuss and therefore does not have any discussion of project-specific alternative technologies to discuss.

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 42 electrical cooperatives and public power districts (Utility

Members). With Utility Members 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 Utility 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 Utility Members create long-range plans and other work plans that they provide periodically to Tri-State's Transmission Planning Department. When Utility Members' plans indicate the need for system upgrades or new construction, Utility Members 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 Utility Members' 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 2022 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 Utility Members; 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 its Utility Members, 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, or modification of existing, 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 2022 Plan, it is important to recognize the key differences between Tri-State and other Colorado utilities. Tri-State is a cooperative owned by its 45 members, including 42 distribution cooperatives and public power systems located in four states: Colorado, Nebraska, New Mexico, and Wyoming. The territories served by Tri-State's Utility Members 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 sets the rates charged to Tri-State's Utility Members accordingly. Tri-State's primary mission is to provide its Utility Members 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 2022 Transmission Plan includes transmission, sub-station, 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 improve-ments, congestion relief, or the accommodation of new generation. It should be noted that the 2022 Plan includes some projects listed in the 2020 Plan.

In January 2020, Tri-State's board of directors approved and announced that Tri-State is implementing its REP, a transition to clean energy that will provide reliable, affordable, and responsible electricity for its Utility Members. The REP commits Tri-State and its Utility Members to significant reductions in emissions of carbon dioxide attributable to Tri-State's electricity sales to its Colorado Utility 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 Responsible Energy Plan Task Force have identified several viable transmission alternatives that would support increased generation in the region by building new transmission 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 GHG 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.

Table 5. Load-serving projects included in the Tri-State 2022 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Big Sandy-Badger Creek 230 kV Line	2028	$86.4	Req'd
Burlington-Lamar 230 kV Line	2025	$106.5	Issued
Del Camino-Slater 115 kV Line Uprate	2022	$1.4	NR
Lost Canyon-Main Switch 115 kV Line**	TBD	TBD	NR
Vollmer Project	2022	$7.1	NR

***These are conceptual projects*

Big Sandy-Badger Creek 230 kV Line

The proposed Big Sandy-Badger Creek 230 kV line is intended to increase reliability in the project area, improve load-serving capability, reduce curtailment of eastern Colorado network resources under prior outage conditions, and allow the potential development of new renewable generation resources in the area. This will be accomplished by adding a new 230 kV line from the existing Big Sandy substation to a new Badger Creek switching station in eastern Colorado. Badger Creek switching station will sectionalize the existing Henry Lake-Story 230kV line near Hoyt, Colo.

Burlington-Lamar 230 kV Line

Past studies in the Boone-Lamar area of Colorado have shown voltage collapse concerns 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 load 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.

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.

Lost Canyon-Main Switch 115 kV Line

There is potential for heavy load growth and resource development 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 future load growth and resource development for the CO2 Loop in southwestern Colorado.

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.

Table 6. Reliability projects included in the Tri-State 2022 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Big Sandy-Badger Creek 230 kV Line	2028	$86.4	Req'd
Big Sandy-Burlington 230 kV Line Uprate	2028	$7.7	NR
Burlington-Burlington (KCEA) Rebuild	2024	$0.7	NR
Burlington-Lamar 230 kV Line	2025	$106.5	Issued
Cahone-Empire 115 kV Line Uprate	2023	$0.9	NR
Del Camino-Slater 115 kV Line Uprate	2022	$1.4	NR
Falcon-Paddock-Calhan 115 kV Line**	TBD	TBD	NR
Lost Canyon-Main Switch 115 kV Line**	TBD	TBD	NR
San Luis Valley-Poncha 230 kV Line #2**	TBD	TBD	Req'd
Slater Double Circuit Conversion	2024	$4.1	NR

***These are conceptual projects*

Big Sandy-Badger Creek 230 kV Line

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

Big Sandy-Burlington 230 kV Line Uprate

The 81-mile-long Big Sandy-Windtalker-Landsman Creek-Burlington 230 kV line is old and undersized based on modern design standards. To ensure continued reliability of the eastern Colorado transmission system, Tri-State is uprating the existing Big Sandy-Burlington 230 kV line through structure modifications and/or replacements to allow at least 75-degree operation. This project will improve reliability of the eastern Colorado transmission system and allow the potential development of new renewable generation resources 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 rebuild the existing Burlington-Burlington

KCEA line to increase the thermal rating of the line. The increased capacity also will help K.C. Electric Association serve new load in the area.

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

Cahone-Empire 115 kV Line Uprate

This project will replace structures on limiting spans on the Cahone-Great Cut Tap-Empire 115 kV line to allow 100-degree C operation. The project also will include terminal equipment upgrades at Cahone to allow 100-degree C operation of the line. The increased line rating will address existing operational and maintenance constraints on this line.

Del Camino-Slater 115 kV Line Uprate

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

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 Mountain View Electric Association's ("MVEA") 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 115kV Line

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

San Luis Valley-Poncha 230 kV Line #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. This conceptual project is being reevaluated in the CCPG San Luis Valley Subcommittee to explore alternatives to 230 kV transmission development.

Slater Double Circuit Conversion

This project will rebuild the Del Camino Tap-Slater 115 kV line as a double circuit line. This will result in the removal of the three-terminal line between Longs Peak, Meadow, and Slater substations, and the creation of separate Longs Peak-Slater and Meadow-Slater 115 kV lines. The project will increase reliability on the area transmission system and improve operational and maintenance challenges.

Table 7. Generation Congestion projects in the Tri-State 2022 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Big Sandy-Badger Creek 230 kV Line	2028	$86.4	Req’d
Big Sandy-Burlington 230 kV Line Uprate	2028	$7.7	NR
Boone-Huckleberry 230 kV Line	2026	$40.3	Req’d
Burlington-Lamar 230 kV	2025	$58.4	Issued

Big Sandy-Badger Creek 230 kV Line

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

Big Sandy-Burlington 230 kV Line Uprate

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

Boone-Huckleberry 230 kV Line

The proposed Boone-Huckleberry 230 kV line is intended to provide connectivity across Tri-State's four-state transmission system, which currently is not connected in southeast Colorado. The connection will allow geographically diverse generation resources to be moved across Tri-State's four-state service area. This will be accomplished by adding a new 230 kV line from the existing Boone substation to a new Huckleberry substation in southeast Colorado. Huckleberry substation will sectionalize the existing Comanche-Walsenburg 230kV line south of Pueblo, Colorado.

Burlington-Lamar 230 kV Line

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

3. Tri-State Alternative Technologies

Tri-State's 2022 Transmission Plan includes five new projects: Big Sandy-Badger Creek 230 kV Line, Big Sandy-Burlington 230 kV Line Uprate, Boone-Huckleberry 230 kV Line, Cahone-Empire 115 kV Line Uprate, and the Slater Double Circuit Conversion. Alternative technologies, such as non-wires alternatives and advanced transmission technologies, were considered in the development of each of these transmission projects.

The Big Sandy-Badger Creek 230 kV Line was selected as opposed to non-wires alternatives or advanced transmission technologies due to the ability of a new transmission line to accommodate new renewable generation resources, improve transmission system reliability, and mitigate generation curtailment in eastern Colorado under 230 kV prior outage conditions. Studies performed in CCPG's Responsible Energy Plan Task Force ("REPTF") demonstrated the inability of non-wires alternatives or advanced transmission technologies alone to meet the same objectives and needs identified in eastern Colorado.

The Big Sandy-Burlington 230 kV Line Uprate was selected as opposed to non-wires alternatives or advanced transmission technologies due to the ability of modifications to existing transmission facilities to accommodate new renewable generation resources, improve transmission system reliability, and mitigate generation curtailment in eastern Colorado under 230 kV prior outage conditions. The replacement of existing, aging infrastructure provides higher, long-term capacity on the transmission system, increases reliability, and reduces operational and maintenance constraints. Studies performed in CCPG's REPTF demonstrated the inability of non-wires alternatives or advanced transmission technologies alone to meet the same objectives and needs identified in eastern Colorado.

The Boone-Huckleberry 230 kV Line was selected as opposed to non-wires alternatives or advanced transmission technologies due to the ability of new transmission to close a transmission gap across Tri-State's four-state service area. Non-wires alternatives or advanced transmission technologies cannot provide connectivity on the transmission system.

The Cahone-Empire 115 kV Line Uprate was selected as opposed to non-wires alternatives or advanced transmission technologies due to its ability to economically increase the Cahone-Empire 115 kV line rating through limited replacements of existing equipment. The replacement of existing, aging infrastructure provides higher long-term capacity on the transmission system, increases reliability, and reduces operational and maintenance constraints.

The Slater Double Circuit Conversion was selected as opposed to non-wires alternatives or advanced transmission technologies due to its ability to economically remove a three-terminal line between Longs Peak, Meadow, and Slater substations through conversion of a short section of an existing line (<2 miles) from single circuit to double circuit. Non-wires alternatives or advanced transmission technologies could not replace the reliability and operational benefits from the creation of separate Longs Peak-Slater and Meadow-Slater 115 kV lines.

Information concerning the specific Colorado projects included in the Tri-State 2022 10-Year plan is contained in Appendix E. Additional information and supporting documentation can be found at Tri-State's website.

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 peaks in the summer, with a 2021 peak customer demand of approximately 7,200 Megawatts ("MW"). The entire Public Service transmission network is located within the State of Colorado and consists of over 4,900 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 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 facilitate the development of electric infrastructure that maintains system reliability, responds to interconnection and transmission service requests, meets load growth and enables integration of new resources, and fulfills the following principles:

- Maintain reliable electric service by adequate transmission capacity and operational flexibility;
- Provide 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 variables that go into 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. Each of these individual variables may carry with them some level of uncertainty. As transmission planners consider different planning horizons, such as two-, five- and 10-year study models, they seek to determine appropriate transmission solutions, including non-wire alternatives and grid enhancing technologies in addition to transmission upgrades or expansion, which can reliably meet the above-outlined objectives while serving the customer's needs in an efficient manner.

The transmission planning process conducted by Public Service includes a series of open planning meetings that allows interested parties and other stakeholders the opportunity to provide input into and participate in all stages of development of the Public Service transmission plan. Further, 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. An example of this coordination can be seen through the Company's participation in the Colorado Coordinated Planning Group and its individual subcommittees, task forces and working groups as well as the Company's yearly (in Q1 and Q4) stakeholder engagements in accordance with FERC Order 890.

One of the strategic priorities for Public Service is to be a leader in transitioning its resource mix toward cleaner energy sources. The Company's strategic goal is to achieve 80% reduction in carbon emissions by 2030 toward the ultimate goal of zero carbon emissions by 2050. The resulting resource and grid transformation need has impacted transmission planning over the last four years and will continue to have an increasing impact on transmission planning into the future.

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. The Company further notes that the cost estimates and project scopes for not yet in-service projects are subject to change as they are further refined over time.

Table 8. Public Service 10-Year Plan

Project Name	ISD	Cost (millions)	CPCN
Completed			
Shortgrass Switching Station	2020	$22.1	G
Shortgrass – Cheyenne Ridge 345 kV Transmission	2020	$62.4	G
NREL Substation	2020	$12.1	NR
Keenesburg Substation - Generation Interconnect (CEPP bid W090)	2020	$0.2	R
New Planned			
Midway Substation – Generation Interconnect (CEPP bid 056)	2022	$1.7	R
Comanche Substation – Generation Interconnect (CEPP bid 077)	2022	$1.8	R
CEPP Transmission Service Network Upgrades	2023	$15.7	R
Stagecoach Switching Station	2024	$11	U
Colorado's Power Pathway (Including May Valley-Longhorn Segment)	2027	$1,700 ($2,100)	R
Previously Listed Projects			
Greenwood – Denver Terminal 230kV line	2022	$74.7	G
Avery Substation	2022	$12.1	G

Project Name	**ISD**	**Cost (millions)**	**CPCN**
Mirasol (formerly Badger Hills) Switching Station (CEPP Bid X647)	2022	$24.2	R
Tundra Switching Station (CEPP Bid X645)	2022	$22.9	R
CEPP Switching Station Bid S085 (*Canceled*)	~~2022~~	~~$12.0~~	~~R~~
Bluestone Valley Substation Phase 2	2023	16.1	NR
Ault-Cloverly 230/115 kV Transmission	2024	$84.7	G
Avon-Gilman 115 kV Transmission	2024	$11.4	NR
CEPP Voltage/Reactive Support	2024	$79.4	G
Conceptual			
Weld-Rosedale-Box Elder – Ennis 230/115kV Transmission	TBD	TBD	R
Weld County Transmission Expansion	TBD	TBD	R
Glenwood-Rifle 115 kV Transmission	TBD	TBD	U
Hayden-Foidel Creek - Gore Pass 230 kV	TBD	TBD	U
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	TBD	TBD	R
Poncha – Front Range 230 kV	TBD	TBD	R
Carbondale – Crystal 115 kV Transmission	TBD	TBD	R
Pathway Voltage Control / Support	TBD	TBD	R
Denver Metro Area Upgrades	TBD	TBD	R
Northern Colorado Transmission	TBD	TBD	R
Gateway South – Craig / Hayden Area Transmission	TBD	TBD	R
Distribution Driven Projects			
Barker Distribution Substation	2021	$39.2	G
High Point Distribution Substation	2022	$14.4	G
Waterton Expansion (Previously Titan) Distribution Substation	2023	$12.3	G
Stock Show Distribution Substation	2026	TBD	NR
Wilson Distribution Substation	TBD	TBD	NR
Dove Valley Distribution Substation	TBD	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

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

Public Service's transmission plan does not currently include multistate regional transmission projects – these projects are noted as "Northern Colorado Transmission" and "Gateway South – Craig/Hayden Area Transmission" under Conceptual Projects in Table 8 above.

Following is a brief, narrative description of each Public Service project. Information for the projects shown in Table 8, as well as maps of the Public Service projects for each of the categories listed below, can be found in Appendix F.

Planned Projects

Public Service's planned transmission projects generally can be placed in two categories. The first category consists of projects that are needed primarily for load growth or reliability purposes. These include both new transmission facilities as well as capacity upgrades to existing transmission facilities. Public Service's native load growth has remained fairly flat during the past five years. Per the Company's 2021 ERP load forecast, Public Service's native peak demand (retail and firm wholesale requirements) is expected to grow at a compounded annual rate of 0.3 percent through 2030.

The second category consists of transmission 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 transmission plans, since it is intended to promote proactive transmission planning to accommodate renewable resources. The SB07-100 projects are typically larger transmission expansion projects needed to access specific resource-rich areas of the state (i.e. the Colorado ERZs) that have high potential to host future renewable generation facilities. Most SB07-100 projects completed to date comprise the existing backbone transmission that will be gainfully leveraged to accommodate the Clean Energy Plan (proposed in Proceeding No. 21A-0141E) and Destination 2050 goals.

Projects Completed Since 2020

This section describes the Public Service projects that have been placed in-service since the 2020 Rule 3627 10-Year Transmission Plan ("2020 Plan"). The following project(s) consisted of upgrades or additions to existing substations.

NREL Substation

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 did not require a CPCN and was placed in-service in 2020 at a cost of $12.1 million.

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 that extends 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 interconnects the 300 MW Bronco Plains wind project and the Cheyenne Ridge 500 MW wind project that are included in the Company's Colorado Energy Plan Portfolio ("CEPP"). The project is located in Lincoln, Kit Carson and Cheyenne counties. The project was granted a CPCN, the cost was approximately $62.4 million and it went in-service in 2020.

New Planned Transmission Projects (Not Included in Previous Rule 3627 Filings)

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

Colorado's Power Pathway

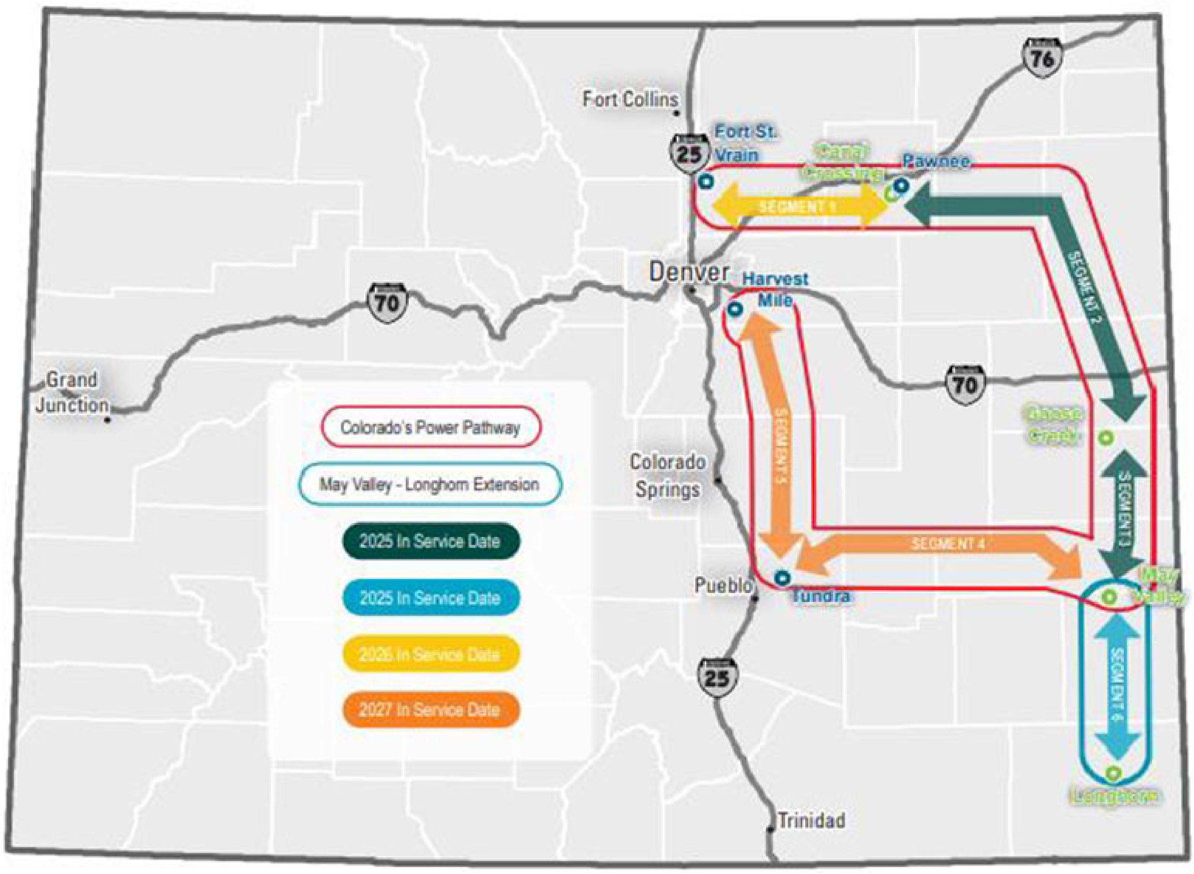
Colorado's Power Pathway is a 345 kV transmission project planned as a means to deliver an estimated 3000 to 3500 MW of simultaneous power output from new renewable energy resources located in eastern and southern Colorado. The primary driver for Public Service is to meet 80 percent carbon reduction from 2005 carbon levels by 2030. The project was identified within the 80x30 Task Force as a part of the Colorado Coordinated Planning Group. The planned project consists of approximately 560 miles of double circuit 345 kV lines for providing transmission access to Energy Resource Zones ("ERZs") 1, 2, 3, and 5, and connecting them to the Denver Metro Area. A CPCN was submitted for approval on March 2, 2021, with an expected decision in early 2022 (Proceeding No. 21A-0096E). The project includes the following transmission facilities:

- A new Canal Crossing Station near the Pawnee Substation
- A new Goose Creek Station near the Cheyenne Ridge Wind Project
- A new May Valley Station near the Lamar Substation
- 345 kV double-circuit transmission line between Canal Crossing/Pawnee and Fort St. Vrain
- 345 kV double-circuit transmission line between Canal Crossing and Goose Creek/Cheyenne Ridge
- 345 kV double-circuit transmission line between Goose Creek and May Valley/Lamar
- 345 kV double-circuit transmission line between May Valley and Tundra
- 345 kV double-circuit transmission line between Tundra and Harvest Mile
- Contingent on ERP need: A new Longhorn Station in Baca County
- Contingent on ERP need: 345 kV double-circuit transmission line between May Valley and Longhorn

Colorado's Power Pathway project is estimated to cost approximately $1.7 billion ($2.1 billion with contingent segments) and in-service dates for the segments ranging from

2025 to 2027. The project was identified within the 80x30 Task Force as a part of the CCPG.

Figure 7: Colorado's Power Pathway



Stagecoach Switching Station

A new 230kV switching station is needed to connect GI-2014-9, a 70 MW photovoltaic ("PV") solar generation facility in Pueblo County, Colorado. The Point of Interconnection ("POI") requested for GI-2014-9 is a tap on the Comanche - Midway 230kV line at approximately 5.5 miles from the Comanche Substation. The tap point will consist of construction of a new station at the POI, which will be referred to as "Stagecoach Switching Station". The planned in-service date is 2024 and a CPCN may be needed.

Colorado Energy Plan Portfolio (CEPP) – Transmission Service Network Upgrades

The Interconnection of CEPP bid 056 at Midway Substation has resulted in the need for transmission service network upgrades. The first network upgrade needed is to reconductor the 230kV line from Daniels Park Substation to Prairie Substation. The second network upgrade is to upgrade the transformer at Midway Substation. Both upgrades have planned in-service dates of 2023. A CPCN for these facilities is expected to be filed in the first quarter of 2022.

CEPP Generation Interconnection Facilities

Currently, the interconnection facilities needed to accommodate the CEPP generation include expanding or upgrading three existing substations and constructing two new switching stations. The three existing substations to be modified are the Keenesburg, Comanche, and Midway substations, and the Company will file a CPCN for these interconnection facilities in the first quarter of 2022. The two new switching stations are the Mirasol 230kV Switching Station and the Tundra 345 kV Switching Station (detailed descriptions provided below in the Planned Transmission Projects section). The Company filed a CPCN for these interconnection facilities on June 24, 2021. A Commission decision is expected in the first quarter of 2022.

Planned Transmission Projects (Included in Previous Rule 3627 Filings)

Colorado Energy Plan Portfolio (CEPP) Projects

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 CEPP approved as part of the Company’s 2016 ERP. The new line will be implemented by rebuilding existing transmission facilities from the Greenwood Substation to the Denver Terminal Substation within existing 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 $74.7 million and it is planned to be in service by December 31, 2022. The Company filed a CPCN for this project on February 21, 2020, and received the CPCN approval on September 10, 2020.

CEPP Voltage/Reactive Support

Several voltage/reactive support devices have been installed on the Public Service transmission system to accommodate the CEPP generation. The STATCOM project to control voltage flicker due to the CF&I (Evraz) arc furnace has been updated from a 2023 in-service date to 2024 in order to perform some additional studies. The costs also have been adjusted to reflect updated scope definition.

Table 9. CEPP Voltage Control Facilities

Substation / Switchyard Location	**Implementation**	**Estimated In-Service Date**	**Estimated Cost (millions)**
	Devices to be installed		
CF&I Furnace	± 95 MVAR STATCOM	Dec. 2024	$13.0
	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	$6.5
	One (1) 120 MVAR capacitor		
Harvest Mile	240 MVAR of shunt capacitance	Oct 2020	$8.3
	Two (2) 120 MVAR capacitors		
Missile Site	360 MVAR of shunt capacitance	Oct 2020	$15.8
	Three (3) 120 MVAR capacitors		
	Rush Creek Master Voltage Controller AVSO	Dec. 2020	$1.2
Pronghorn	± 150 MVAR STATCOM	Dec. 2020	$30.1
	One (1) dynamic voltage support device		
Shortgrass	60 MVAR of shunt reactance	April 2020	$4.5
	Two (2) 30 MVAR reactors		
Total			**$79.4**

The cost of the combined facilities is estimated to be approximately $79.4 million and they will be placed in service between 2020 and 2024. The Company filed a CPCN for these projects in December 2019 and received the CPCN approval on September 10, 2020.

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 and was referenced in the 2020 filing as Mirasol switching station. This project is one of several generator interconnection switching stations that will be needed to accommodate the resources procured for Public Service 2017 CEPP. The Mirasol Switching Station will be located approximately 12 miles southeast of Comanche Substation and will intercept one of the two Comanche - Midway 230 kV lines. The project has a planned in-service date of 2022, with an estimated cost of $24.2 million. The Company included this project with other generator interconnection switching stations when it filed a CPCN for these CEPP interconnection facilities in 2021 (Proceeding No. 21A-0298E).

Tundra Switching Station (Previously CEPP Switching Station X645)

This project is presently planned as a 345 kV switching station to interconnect generation. The station is one of several generator interconnection switching stations that will be needed to accommodate the resources procured for Public Service 2017 CEPP. The Tundra Switching Station will be located approximately 13 miles northeast of Comanche Substation, and will intercept one of the two Comanche – Daniels Park 345 kV lines. The project has a planned in-service date of 2022, with an estimated cost of $22.9 million. The Company included this project with the other generator interconnection switching stations when it filed a CPCN for these CEPP interconnection facilities in 2021 (Proceeding No. 21A-0298E).

CEPP Switching Station S085

This project has been canceled due to project withdrawal by the developer.

Other (non-CEPP) Projects

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 lines will connect with two new Public Service substations:

(1) Husky 230/115 kV Substation, which is planned to be built near the existing PSCo Ault 44 kV Substation and will be its replacement, and

(2) Graham Creek 230/115 kV Substation, which is planned to be built near the existing Eaton 44 kV Substation and will be its replacement. 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 2024, with an estimated cost of $84.7 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 the Holy Cross Energy 115kV system. The project does not require a CPCN, has a planned in-service date of 2024, and has an estimated cost of $11.4 million.

Avery Substation

The original project work orders refer to this project as DCP Timnath because it is a new distribution substation near Timnath, Colorado. As the project developed, it became known as the Avery Substation Project. The project consists of building a new Avery Substation in Weld County approximately 3 miles south of the Platte River Power Authority Ault – Timberline 230 kV line. The new Avery substation will tap the Ault – Timberline 230 kV transmission line using 230 kV double-circuit transmission and an in-and-out termination configuration. The substation will include a three-breaker ring design and a single 230/13.8 kV, 28 MVA transformer, but built to accommodate two 230/13.8 kV, 28 MVA transformers for future load growth. This project is needed to serve new load growth and development in the Timnath area. A CPCN was granted for this project by Decision No. C15-0461 in Proceeding No. 15A-0159E.

Bluestone Valley Substation Expansion (Phase 2)

The Bluestone Valley Phase 2 project consists 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. The project does not require a CPCN per CPUC Decision No. C21-0256-I and has a planned in-service date of 2023, with an estimated cost of $16.1 million.

3. Public Service Conceptual Transmission Plans

Conceptual Transmission 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.

<u>Conceptual Plans Related to Load Growth</u>

Glenwood–Rifle 115 kV Transmission

This plan has been described in previous filings and consists of upgrading the Glenwood Springs – Mitchell Creek – New Castle – Silt Tap – Rifle Ute line from 69 kV to 115 kV. Implementation of the voltage upgrade will depend on future load growth and reliability.

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. The project was studied jointly with other Colorado transmission utilities as part of a CCPG joint study in 2020. The joint study group concluded that the projected expense of the project may not be justified due to the planned and/or proposed generating unit retirements at Craig and Hayden.

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 serve load growth in the region.

Rifle–Story Gulch Transmission

The project has been described in previous filings and would consist of a new radial 230kV 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.

Wheeler–Wolf Ranch 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 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.

Carbondale – Crystal Transmission

The conceptual project will address potential reliability concerns due to expected load growth in the Carbondale area in Garfield County. The project study scope will be developed in coordination with Holy Cross Electric and other interested stakeholders.

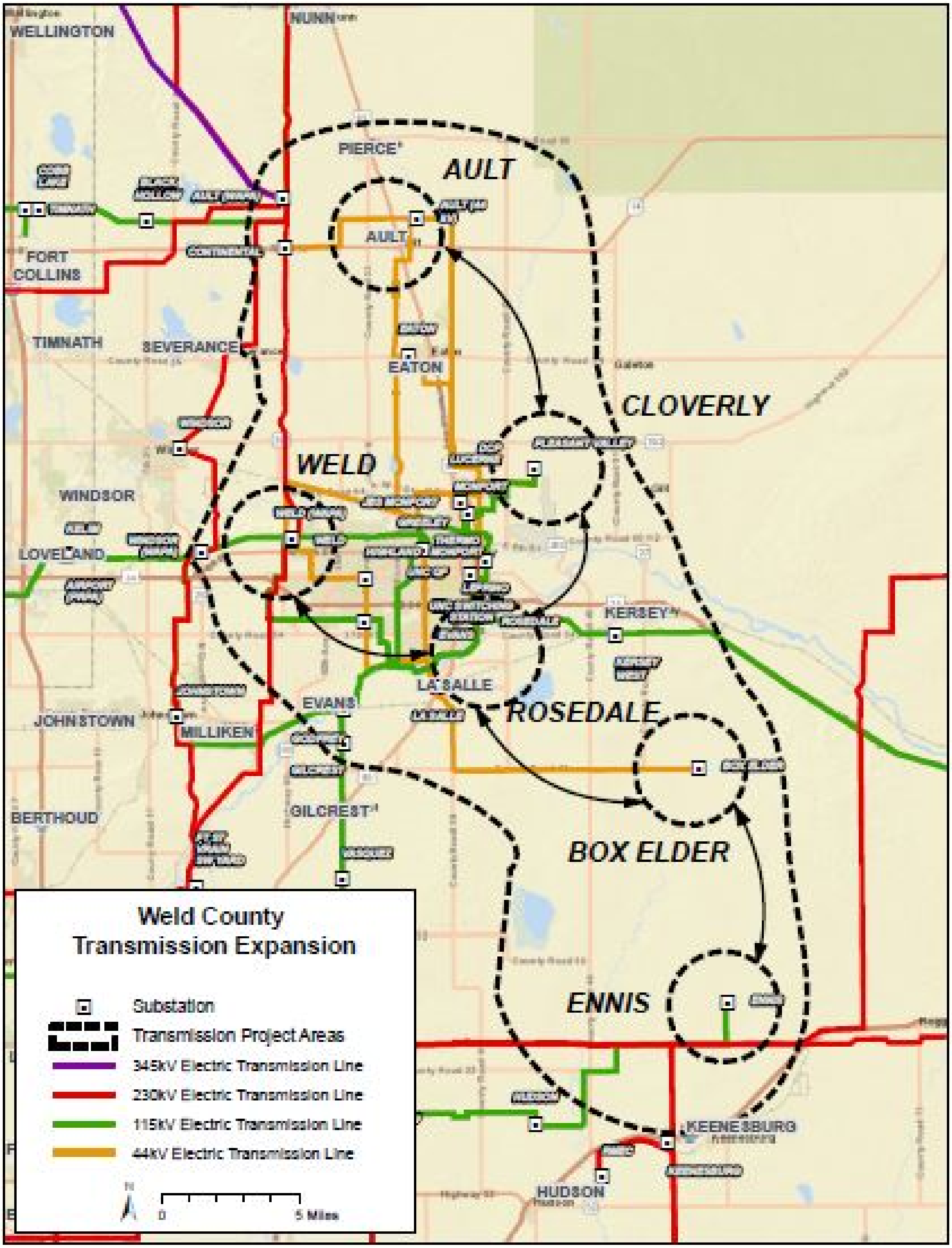
Weld–Rosedale–Box Elder–Ennis Transmission

Public Service has been working through the CCPG Northeast Colorado (“NECO”) Subcommittee to study and evaluate transmission alternatives for the area south of Greeley. The objectives are 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 planned transmission projects 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. This project is conceptual pending completion of the NECO studies to identify the preferred alternative and target in service date.

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

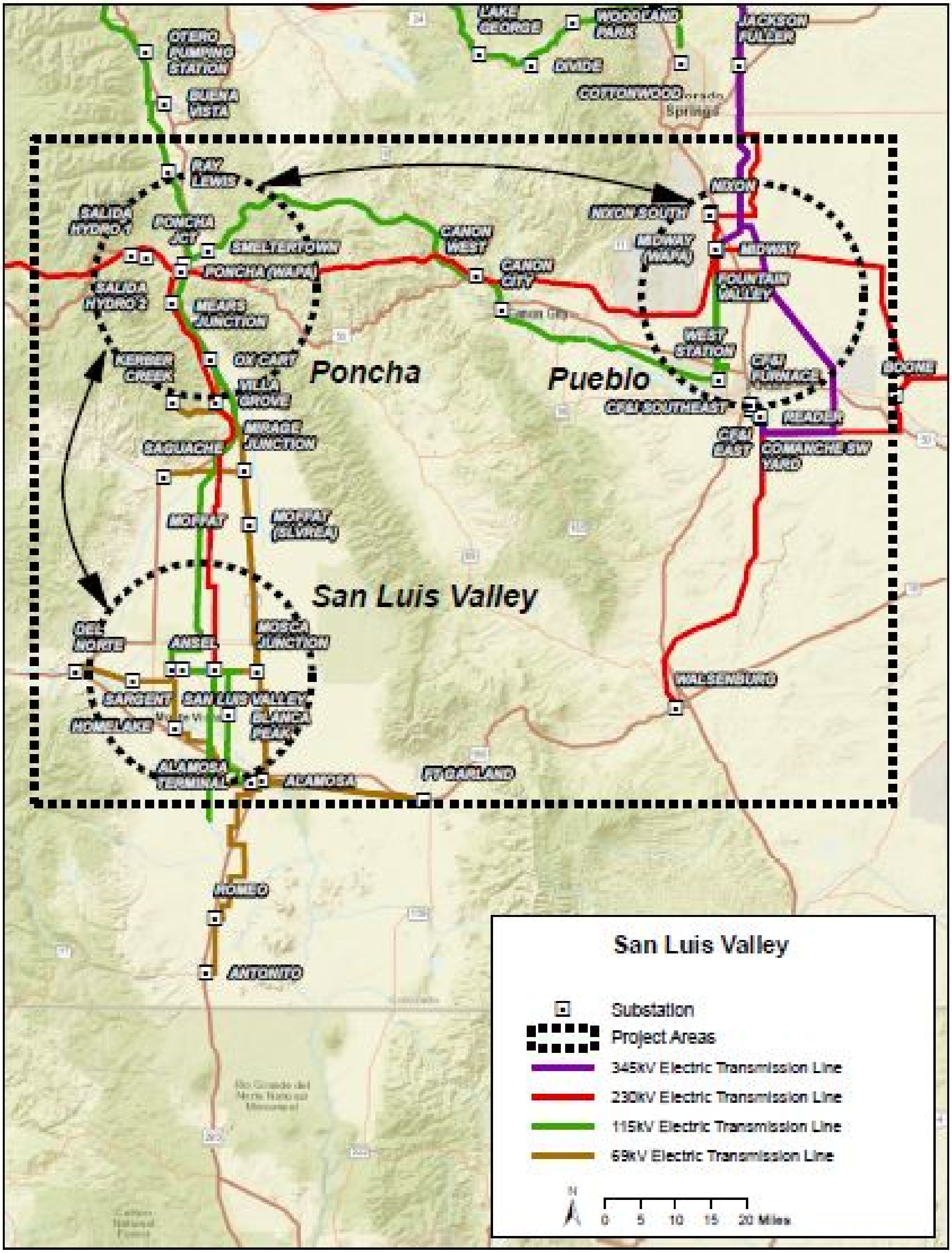
Weld County Transmission Expansion

This project would allow interconnection of new resources and complement other transmission plans in northeast Colorado, such as the Ault-Cloverly Project and the Weld-Rosedale-Box Elder-Ennis Project. The Weld County Expansion continues to be a general placeholder that captures the transmission 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 Project or the Weld County Expansion could be a new project with a potential focus to improve import and export capability between Public Service and northern systems. Regardless, the Weld County Expansion would be a project that helps Public Service meet its CEP goals.


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
AULT
CLOVERLY
WELD
ROSEDALE
BOX ELDER
ENNIS
WELLINGTON
NUNN
PIERCE
FORT COLLINS
TIMNATH
SEVERANCE
EATON
WINDSOR
LOVELAND
KERSEY
LA SALLE
EVANS
JOHNSTOWN
MILLIKEN
GILCREST
BERTHOUD
KEENESBURG
HUDSON

San Luis Valley – Poncha 230 kV & Poncha – Front Range 230 kV

Like Tri-State, Public Service also recognizes that new high-voltage transmission into the San Luis Valley would help improve electric system reliability and customer load-serving capability and accommodate development of additional renewable generation resources. Past studies by the CCPG San Luis Valley Task Force ("SLVTF") 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. Additional transmission beyond Poncha to the Front Range not only would enhance reliability but also provide additional transfer capability to move power generated in the San Luis Valley to the Front Range transmission system and help Public Service meet its CEP goals. Due to a renewed interest in the San Luis Valley, the SLVTF and interested stakeholders will initiate an effort to update past studies and refresh the transmission alternatives in the area.


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

Pathway Voltage Control / Reactive Support and Grid Strengthening

Public Service expects Colorado's Power Pathway project and the substantial amount of new generation interconnected to the project will require voltage control and dynamic reactive support facilities at specific system locations to maintain voltages within acceptable steady-state and dynamic performance limits. Additionally, grid strengthening facilities also may be needed to partly compensate for the erosion of system strength (short-circuit current levels) due to synchronous generator retirements Public Service will determine the size and location of dynamic reactive support and grid strengthening facilities based on the preferred generation portfolios identified from the 2021 ERP and CEP bid solicitation process. The planned facilities will be determined once the 2021 ERP and CEP is approved, and the locations and sizes of resource acquisitions are known.

Denver Metro Area Upgrades

Public Service expects that the delivery of future increased levels of renewable generation (needed for carbon reduction goals) to the Denver Metro load center will result in higher capacity need for the Denver Metro area transmission system. Public Service will study potential capacity upgrade alternatives and identify the appropriate projects based on the preferred generation portfolios identified from the 2021 ERP and CEP bid solicitation process. The planned Denver Metro area upgrades will be determined once the 2021 ERP and CEP is approved, and the locations and sizes of resource acquisitions are known.

Northern Colorado Transmission

Public Service is conceptually exploring how to enhance the bi-directional power transfer capability into the Public Service system. Achieving this goal would require increased transmission connectivity with neighboring out-of-state entities. One such conceptual project could include transmission expansion from existing Public Service facilities toward the Wyoming-Colorado border. Benefits may include improved system reliability, as well as improved access to potential organized markets in the Western

Interconnection for economic power transactions. Studies will be coordinated with the newly formed CCPG North By Northwest Task Force.

Gateway South – Craig/Hayden Area Transmission

Public Service is conceptually exploring how to enhance the bi-directional power transfer capability into the Public Service system. Achieving this goal would require increased transmission connectivity with neighboring out-of-state entities. Public Service has conceptualized a plan to expand transmission in the northwest region of Colorado to interconnect with the PacifiCorp Gateway South 500 kV Project. The plan would consider developing transmission from the existing Craig/Hayden area to a feasible interconnection point along the PacifiCorp Gateway South 500 kV transmission line. Benefits may include improved reliability, as well as improved access to potential organized markets in the Western Interconnection for economic power transactions. Studies will be coordinated with the appropriate CCPG task force.

Other Long-Range Distribution Planning Substation Projects

Public Service, the Office of the Utility Consumer Advocate ("UCA"), 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 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 to be determined.

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	2025	$39.2
Dove Valley	115 kV	Near I-25 and C-470 in Arapahoe County	TBD	TBD

Substation Project Name	Transmission Voltage	Approximate location	Potential ISD	Cost ($M)
High Point	230 kV	Near Denver International Airport; Adams County	2022	$14.4
Waterton Expansion (previously referred to as Titan)	230 kV	Near Sterling Ranch in Douglas County	2023	$12.3
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 2022 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

4. Public Service Alternative Technologies

Public Service Methodology for Evaluating Project Alternatives

Public Service follows the Company's established process for evaluating project alternatives per the Company's approved tariff and Attachment R. Per Attachment R Section II(C)(8), "…Public Service shall evaluate alternatives on the basis of: (1) ability to mitigate any criteria of NERC Reliability Standards issues; (2) ability to mitigate those issues over the time frames of the study; (3) comparison of the capital costs of the demand response, as comparted to other transmission alternatives; and (5) comparison of any operational benefits or issues between demand responses or transmission alternatives. From this comparison, the most appropriate project alternatives can be selected."

Projects for which Non-Wire Alternative and/or Advanced Technology Alternative was Actively Evaluated

Colorado's Power Pathway Project

Colorado's Power Pathway Project is a new project in this filing and can be considered a conventional solution per the CPUC Decision R21-0073, as opposed to a non-wire alternative ("NWA"). The purpose of Colorado's Power Pathway project is to develop a transmission expansion plan, which will enable Colorado utilities to achieve the 80 percent reduction in carbon emissions by 2030 as described in SB 19-236. Public Service did consider storage resources as a potential alternative to transmission facilities comprising Colorado's Pathway Project. However, it quickly became evident that, fundamentally, storage does not offer a reasonable alternative from a technical or practical perspective.

Further, the above-mentioned advanced technologies in Section II.D also were discussed during the CCPG 80x30 Task Force, which is responsible for the study and development of what is now called the Colorado Power Pathway project. Of the mentioned technologies, only specialized conductors were most relevant to this project's goal of delivering the resources from the remote energy resource zones into the centralized load centers. Public Service maintains that relevant concerns remain with the use or deployment of non-standard equipment on its system from an inventory management perspective, as it would require specialized personnel and/or training for maintaining the special construction/equipment. Thus, the Company has chosen a conventional wired transmission project, as described in this Plan, which meets the Company's goals while providing safe, reliable, and cost-effective electric service.

Projects for which Non-Wire Alternative was and/or Advanced Technology Alternative Selected

Public Service does not have a planned project for which a non-wire alternative has been selected in this 10-Year Plan.

IV. Projects of Other CCPG Transmission Providers

In addition to the projects planned by Black Hills, Tri-State, and Public Service contained in this 2022 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
2022	Nixon-Kelker 230 kV Line Uprate	Increase clearance on Nixon-Kelker 230 kV line to increase facility rating on the line.	Increase facility rating
2023	North System Improvements	Briargate Sub Expansion and 230/115kV Autotransformer Intercept Fuller-Cottonwood 230kV Line Fuller-Cottonwood Line Uprate	Reliability
2023	South System Improvements	Nixon-Fountain 115kV Reconductor Fountain-Bradley 115kV Reconductor	Increase facility rating
2025	Central System Improvements	New Kelker-South Plant 115kV Line Rebuild Kelker Substation to Full Breaker and a Half (230 and 115kV)	Reliability
2024	Flying Horse Flow Mitigation	Install Series Reactor on Flying Horse-Monument 115kV Line Section to Mitigate Inadvertent Power Flows	Reliability
2023	Fuller Transformer	Fuller 230/12.5kV Power Transformer Addition	Load serving
2023	Horizon Substation and Transformer	New Horizon Substation and Transformer Addition	Load serving
2023	Kettle Creek Transformer	Kettle Creek 115/12.5kV Power Transformer Addition	Load serving
2025	Flying Horse Transformer	Flying Horse 115/12.5kV Power Transformer Addition	Load serving

In-Service	Project Name	Description	Purpose
2024	Claremont Transformer	Claremont 230/34.5kV Power Transformer Addition	Load serving
2023	Pike Solar and BESS	175 MW Solar PV Project and 75 MW BESS Interconnection – Williams Creek Substation	Generator interconnection - renewable PPA

This information is provided voluntarily by Colorado Springs Utilities ("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
2024	Black Hollow Sun (BHS) Project	Sectionalize Carey-Ault 230kV Line with new substation to interconnect BHS solar plant.	New renewable solar energy resource

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
2021	Midway KV1A Replacement	Replacing KV1A at Midway	Replacing aging equipment and increasing size

In-Service	Project Name	Description	Purpose
2025	Weld KV1A	Replace KV1A at Weld due to condition/age. Convert to breaker and half to increase reliability.	Replace aging equipment and increasing size
2025	Blue Mesa Reactor and Transformer Project	Install a new reactor and transformer at Blue Mesa substation due to increased area voltage support.	Increase 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).

Rule 3627 was amended in Decision No. R17-0747 in Proceeding No. 17R-0489E to require electric utilities subject to Commission rate regulation to include their transmission plans for energy resource zones required 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; and
d. Submit proposed plans, designations, and applications for Certificates of Public Convenience and Necessity to the Commission for 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 shown in Figure 8, and as described below, 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.

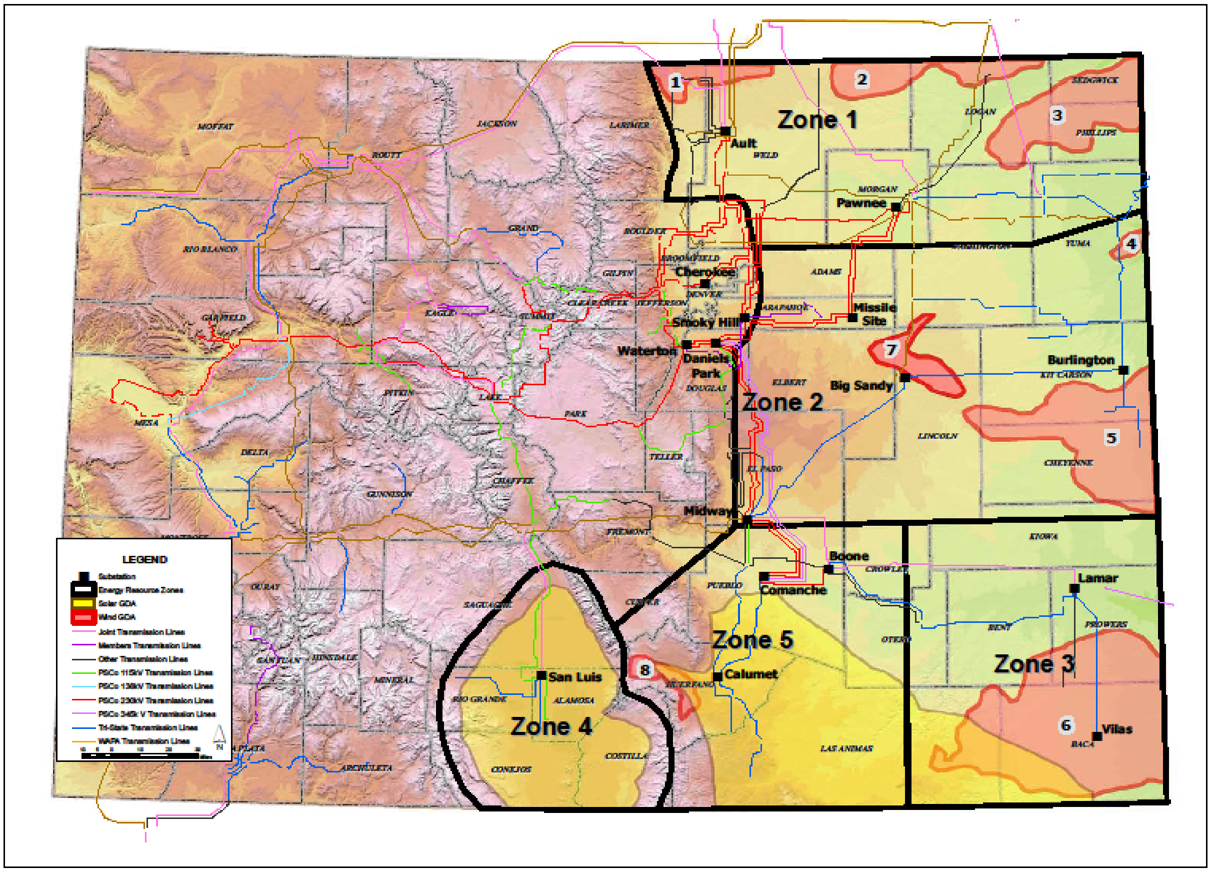
ERZ 4 (San Luis Valley)

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 that includes both potential wind and solar resources.

Figure 8. Map of SB07-100 Energy Resource Zones



In addition to the public policy requirements of SB07-100, all three Companies are subject to public policy requirements. These are described in Section II.B and include 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 these public policy requirements.

A. Black Hills Summary

Black Hills encouraged all interested parties to participate in the 2021 SB07-100 study process. An open stakeholder SB07-100 kickoff meeting was held in conjunction with the Q1 Black Hills Colorado Transmission ("BHCT") Transmission Coordination and Planning Committee ("TCPC") on March 30, 2021, to inform stakeholders of the proposed study plan and to provide an opportunity for suggestions and feedback on the study process. Follow-up e-mails and calendar invites were sent for the Q2, Q3 and Q4 stakeholder meetings, to invite stakeholders to respond with their input while updating them on the progress of the study work. These meetings occurred June 29, 2021, September 28, 2021, and December 14, 2021. 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 2021 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 2030 peak summer load levels to identify any significant adverse impact to the reliability and operating characteristics of the 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 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 2021 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 2030HS study results indicated that the BHCE transmission system could accommodate a 150MW injection at the Baculite Mesa 115kV substation with no required upgrades, assuming all planned projects are in service. Any injection beyond that will cause overloads on the Baculite Mesa – Airport Memorial Park 115 kV line following the N-2 Contingency of the Baculite Mesa – West Station 115 kV #1 & #2 lines.

Boone 115kV Substation: Additionally, the study results indicated that the BHCE transmission system could accommodate a 160MW injection at the Boone 115kV substation. Higher levels of injection into this substation caused overloads on Xcel's Boone 230/115kV transformer during the N-2 contingency of the Boone – Nyberg 115 kV line and the Boone – Dot Tap – Nyberg 115 kV line.

Hogback 115kV Substation: The analysis also looked at injections at the planned Hogback 115kV substation. The results indicated that the BHCE transmission system could accommodate a 100MW injection at this location. Higher levels of injection into this substation caused overloads on the Hogback – Canon West 115 kV line. Injection limits into this area may vary greatly depending on local Canon City load, Turkey Creek PV output, and proposed transmission upgrades that may occur in the next five to 10 years. As injections increased beyond the 100 MW value, there were overloads on the Canon West 230/115 kV transformer, Canon City – Hogback 115 kV line, Hogback 115/69 kV transformer, Canon City – Skala 115 kV line, and Portland – Skala 115 kV line.

Reader 115kV Substation: The analysis indicated that the Reader 115 kV substation could allow for 200 MW of injection. However, this analysis hinges on assumptions that generation retirements and additions in the Comanche area were captured and modeled correctly. Additionally, this injection limit can be impacted by the amount of generation that is entering the system from the Peakview and Rattlesnake wind farms south of the Pueblo system. As generation in the area increases, the risk of overloads in the area will increase following the loss of the Comanche – Daniels Park 345 kV double circuits. In this analysis, the Tundra 345 kV generation was included and flow through the Pueblo 115 kV system was at its peak during the Comanche – Daniels Park 345 kV & Daniels Park – Tundra 345 kV outage. This occurred because losing the 345 kV backbone from Comanche to Denver area load caused the generation to flow through the underlying 230 and 115 kV systems.

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 200 MW injection at this location. In previous study work, high injections at the West Station substation caused issues on the Fountain Valley – Midway 115 kV line. A project to rebuild this line and address limiting substation equipment has increased the rating on the line when compared to previous years' studies.

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 and

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 eight 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	Colorado's Power Pathway	1,2,3,5	2025-2027	CPCN filed March 2, 2021
7	Lamar-Front Range 345 kV	2,3	Canceled	Replaced by Colorado's Power Pathway
8	Lamar-Vilas 230 kV	3	Canceled	Replaced by Colorado's Power Pathway
9	Weld County Expansion	1	TBD	Studies ongoing through CCPG

	Project	ERZ	ISD	Status
10	San Luis Valley	4,5	TBD	Studies complete

1. Completed Projects

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 interconnections from ERZ-2 at the 345 kV voltage level. Completion of this substation also enabled construction of the Pawnee–Smoky Hill 345 kV Project and later the Pawnee-Daniels Park 345 kV Project. The substation facilitated bisecting the Pawnee-Smoky Hill 345 kV line and also allowed for line termination of the future Pawnee-Daniels Park 345 kV Project. The Missile Site 345 kV Substation was placed in-service in December 2012.

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 with interconnection to the Missile Site 345kV Station within its route. 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 placed in-service in June 2013 and was intended as the stepping stone to facilitate construction of the Pawnee-Daniels Park 345 kV Project. 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 interconnected another 800 MW in 2020.

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 Q4 2019, at an actual cost of $174.6 million.

2. Planned and Conceptual Projects

The only planned project is identified as item 6 in Table 14 above. The projected in-service dates for planned projects can be affected by CPCN approval, routing, siting and land permitting, coordination of construction outages, and material delivery times. Assessments will continue on whether the stated factors will cause any modifications to these projects, in terms of configuration, timing, or otherwise.

Colorado's Power Pathway Project (ERZs 1, 2, 3, and 5)

Colorado's Power Pathway Project is described in Section III.C.2. The project consists of building approximately 550 miles of double circuit 345 kV transmission lines in eastern and southern Colorado along the Front Range. The project also will result in constructing a new Canal Crossing 345 kV station near Pawnee Substation, a new Goose Creek 345 kV station near the Cheyenne Ridge Wind Project, and a new May Valley 345 kV station near Lamar Substation. The project also includes a potential extension south of Lamar to a new Longhorn station in Baca County. The project will interconnect with the Fort St. Vrain and Harvest Mile substations within the Denver Metro area. This project was planned in accordance with Senate Bill 07-100, in that it will accommodate generation in designated Energy Resource ERZs 1, 2, 3 and 5. The project has planned segmented in-service dates ranging from 2025 to 2027, at an estimated total cost of approximately $1.7 billion. The estimate for the extension south of Lamar to new Longhorn station is $247 million.

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

This project was developed 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. In 2020, Public Service created an 80x30 Task Force within the CCPG to study new transmission in ERZs 1, 2, 3, and 5 to meet future carbon reduction goals. The 80x30 Task Force Phase I studies resulted in Public Service's proposed Colorado's Power Pathway Project. Colorado's Power Pathway has similar elements to the conceptual Lamar – Front Range project and therefore Public Service has no plans to pursue Lamar – Front Range.

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

The Lamar-Vilas project has been associated with the Lamar-Front Range Plan. The Lamar-Vilas line was planned as 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. Recently, Public Service submitted a CPCN for Colorado's Power Pathway Project that has a potential double-circuit 345 kV transmission south of Lamar into Baca County. Therefore, Public Service has no plans to pursue Lamar-Vilas.

Weld County Transmission Expansion (ERZ-1)

This plan is described in Section III.C.3 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 and 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.C.3 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).

Additional stakeholder outreach is required in Decision No. R21-0073 (Proceeding No. 20M-0008E) at ¶48:

> … all future 10-year plans shall include a record of or copies of stakeholder input from all *transmission-related meetings* in which stakeholders participate, with accompanying narratives describing the Utilities' consideration of alternatives proposed by stakeholders, any analysis conducted in response to stakeholders' requests, utility decisions regarding stakeholder recommendations or requests, and the utility rationale for such decisions. [*emphasis added*]

The Companies define "all transmission-related meetings" as Rule 3627 CCPG and FERC 890 meetings. At these meetings, the Companies will inform stakeholders that any requests by stakeholders for study alternatives should be submitted in writing, post-meeting, to the applicable utility.

Results of written requests from Rule 3627 CCPG meetings, and utility responses and actions, are summarized in the following section to comply with Decision No. R21-0073 at ¶48. Stakeholder outreach and participation with government agencies and other stakeholders at Rule 3627 CCPG meetings also is addressed in the following section.

Results of written requests from FERC 890 meetings, and utility responses and actions, are summarized in Section VII.D to comply with Decision No. R21-0073 at ¶48. Other 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.

Four quarterly meeting invites were sent in 2021 as part of Black Hills' annual TCPC process. The primary kickoff took place on March 30, 2021, and the second, third and fourth invites occurred on June 29, 2021, September 28, 2021, and December 14, 2021. 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 March 30, 2021. It served the purpose of presenting the transmission planning process to stakeholders, describing the scope of the 2021 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 Transmission Plan.

Black Hills' Q2 and Q3 stakeholder meetings were held via phone/web conference on June 29, 2021, and September 28, 2021. This meeting served the purpose of an update and solicitation for feedback regarding the progress of the study and conclusions.

Black Hills' Q4 stakeholder meeting was held on December 14, 2021. The purpose of this meeting was to review study results and the draft LTP report.

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 2021 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 5-mile area surrounding proposed transmission facilities. Federal agencies in the areas of the transmission projects included in Tri-State's 2022 10-Year Transmission Plans include the Bureau of Land Management, the U.S. Forest 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 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 Utility Members, 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 2021, Tri-State hosted one transmission planning-related stakeholder outreach meeting in connection with development of the 2022 10-Year Transmission Plan. The meeting was held on October 15, 2021, 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, nor were any provided during the meeting in October 2020.

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 on Tri-State's website, (select “Operations” then “Details, Stakeholder Outreach and PUC filings”, and “Stakeholder Outreach”).

Tri-State also participates in 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. Significant stakeholder input was received as part of the CCPG REPTF. Appendix M lists REPTF stakeholder comments and responses. 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 2022 10-Year Transmission Plan is available to all government agencies and other stakeholders through Tri-State’s transmission planning website. Tri-State has informed all stakeholders of the availability of the 2022 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, also must 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 subcommittees, working groups and task forces, where it also engages with stakeholders and responds to their comments. 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 stakeholders.

1. Rule 3627 Webinar

The Company developed an informational PowerPoint presentation that included information on the long-range transmission plans developed as part of Rule 3627. A 90-minute virtual webinar session was held on July 15, 2021, to give stakeholders the opportunity to participate and comment on Public Service's transmission plans. The meeting utilized the Microsoft Teams application, which allows for individuals to engage through voice and chat.

More than 500 individuals representing the following stakeholder groups—including 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 Colorado utilities including Black Hills, Colorado Springs, Holy Cross, CORE (previously IREA), Platte River, Tri-State and WAPA Rocky Mountain Region, 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 Public Service's Transmission Plan, also were invited along with local planning office representatives and other staff officials from local governments and agencies. Because line routing activities had not yet started on some of these transmission line projects, which still were 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 and also posted to the Company's website. The information can be found at the following link:

https://www.transmission.xcelenergy.com/Planning/Planning-for-Public-Service-Company-of-Colorado/Colorado-Public-Utilities-Commission-Rule-3627

Attendance at the July 15, 2021, session included approximately 77 webinar attendees. Since self-identification was optional, it was not possible to determine the identity of those who dialed in from a phone line.

The PowerPoint presentation discussed at the July 15, 2021, session was designed to provide a base level understanding of the Company and the transmission planning process, as well as provide an overview of electric transmission to acquaint attendees with basic information about what constitutes the transmission system and how it works. Further, the presentation covered details regarding Public Service's Local Transmission Study plan and updates to planned projects and outlined the many factors that are considered when developing plans. The final portion of the meeting provided stakeholders and interested parties the opportunity to comment on any of the information presented, as well as an opportunity to provide any recommendations or changes to any study item such as scope, methodology, and assumptions. In addition, stakeholders were asked to share any other topics of interest regarding specific electric transmission that they would like to discuss with the group. Written comments were received from an interested stakeholder, Larry Miloshevich. The written comments and other comments received along with Public Service responses to these comments are included in Appendix K.

2. 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 annually in the first and fourth quarters 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 18, 2020, December 9, 2020, March 10, 2021, and December 16, 2021. These meetings were held virtually due to the COVID-19 pandemic. 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".

3. Project-Specific Outreach

Avery Substation Project

Public Service Company of Colorado is currently constructing 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. This connection will supply the proposed Avery Substation with the electrical supply needed to power the distribution feeders serving the immediate communities.

Construction of the substation began in January 2021, with an expected completion date in May 2022. The transmission line construction began in October 2021, with an expected completion date in January 2022.

A public meeting was held on August 16, 2021, to discuss outage concerns in the general area and the Avery Substation construction progress also was discussed.

During the meeting, the public requested regular updates on the progress of the Avery Substation project. In response to this request, a postcard was sent to the nearby residents informing them that project updates that will be made to the project website and to invite them to be part of regular e-mail notifications. The postcard was mailed in September 2021 and the website will be updated as necessary to provide important construction information and project milestones. Subsequent e-mail newsletters also were sent in September and October. These updates will continue until the complete project goes in-service in 2022.

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 Public Service 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 to construct the Northern Colorado Area Plan with the CPUC on March 9, 2017; Proceeding Number 17A-0146E.

The Company held three open house meetings for the Northern Colorado Area Plan in 2020, two of which were held virtually due to the COVID-19 global pandemic. Additionally, in 2021, the Company held two virtual public houses. In August 2021, Public Service submitted a 1041 Areas and Activities of State Interest land use permit application in Weld County, Colorado, and a Use by Special Review Application in Eaton, Colorado. Planning Commission, Board of County Commissioner and Town Board hearings were held in December 2021 and January 2022. Construction updates will be provided to the community and landowners crossed by the project throughout construction in 2022.

Greenwood - Denver Terminal

The Company is currently constructing 15.4 miles of transmission facilities between the Greenwood Substation and the Denver Terminal Substation within existing ROW. This Project is an upgrade from the existing 115kV transmission line to a 230kV transmission line. The project is located in six different jurisdictional boundaries: Centennial, Greenwood Village, Littleton, Englewood, Sheridan, and Denver.

Outreach activities completed with jurisdictions since February 2020 include the following:

<u>City of Centennial:</u>

- November 30, 2020 – City Council
- December 15, 2020 – Mayor, Assistant City Manager, staff
- March 23, 2021 – District 2 Town Hall
- April 6, 2021 – District 1 Town Hall

<u>City of Greenwood Village</u>

- December 3, 2020 – City Manager, staff

<u>City of Littleton</u>

- October 5, 2020 – Littleton Public School District
- November 30, 2020 – City Manager, Department Management

<u>City of Englewood</u>

- July 17, 2020 – City of Englewood Parks Department and South Suburban Parks and Recreation District
- October 23, 2020 - City of Englewood Parks Department and South Suburban Parks and Recreation District
- November 30, 2020 – City Manager
- January 19, 2021 – Mayor Pro Tem, City Council, staff

<u>City of Sheridan</u>

- October 12, 2021 – E-mail to Public Works Director about Segment 3

<u>City of Denver</u>

- February 13, 2020 – City Planner
- September 18, 2020 – Community Planning and Development Department
- September 30, 2020 - Community Planning and Development Department

- February 24, 2021 - Community Planning and Development Department
- October 5, 2021 – Community Planning and Development Department requesting confirmation on permitting requirements for Segments 4 and 5. Subsequent Concept Review Applications were submitted in November 2021.

Southeast Metro Stormwater Authority

- January 20, 2021 – SEMSWA and jurisdictions

Public Open Houses (virtual and in person) were held on the following dates and times:

- October 1, 2020 – Segments 3, 4 and 5
- January 28, 2021 – Segments 1 and 2

Construction of Segment 1 began in May 2021 and was completed in October 2021. Outreach to the jurisdictions is ongoing for sidewalk and road repairs. During construction, regular e-mail newsletters were sent to interested community members to provide a status on the project. The project website also was updated on a regular basis. A notification mailer for the upcoming work on the Greenwood Substation work was sent to landowners around the substation in mid-November 2021.

Foundations for Segment 2 were completed in September 2021 and structure installation started in November 2021.

Construction on Segment 3 began in December 2021 and a notification mailer was sent to landowners along the transmission line in late November 2021.

Barker Substation

The Company is developing plans for the installation of equipment in the currently empty Barker Substation site and a new double-circuit underground 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 expected to occur in 2022.

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 2 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 right-of-way constraints in the current alignment.

Cheyenne Ridge Wind Generation Facility and 345 kV Transmission Line Project

The Cheyenne Ridge 500 MW wind generation facility and the associated 73-mile, 345 kV transmission line (i.e. generation tie-line) is one of the projects that comprises the Company's Colorado Energy Plan. The project is located in Lincoln, Kit Carson and Cheyenne counties, and will generate enough renewable energy to power 270,000 homes. The Company completed its purchase of the project asset from Tradewind Energy, which 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 commenced commercial operation in August 2020. After taking ownership of the project in June 2019, the Company sent brochures on project updates to stakeholders and landowners. The Company continues to interact with landowners in the wind generation facility after commercial operation commenced in August 2020.

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 3627 Subcommittee subgroup in developing the 10-Year Transmission Plan. CCPG's 3627 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.

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 to be considered

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 with 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 are posted on the CCPG section of the WestConnect website.

E. CCPG 80x30 Task Force

The 80x30 Task Force ("80x30TF") was formed on August 20, 2020, to serve as the transmission planning forum to develop the study process and identify the transmission alternatives that most effectively meet the carbon reduction needs of CCPG members and stakeholders. The 80x30TF studies were broken into two phases, with Phase I primarily focused on Public Service's and Tri-State's resource need and carbon reduction goals while Phase II focused on 80x30TF members' alternatives and additional studies requested by stakeholders. Public Service chaired and performed the study work for the 80x30TF.

The following stakeholders participated in the 80x30TF:

- Apex Clean Energy
- Black Hills Energy
- Colorado Springs Utilities
- Dietze & Davis, on behalf of Independent Power Producers
- Enel North America
- Energy Strategies
- Grid Strategies
- Interwest Energy Alliance
- Juwi Inc
- National Grid Renewables
- Office of Consumer Council
- Onshore Wind
- Platte River Power Authority
- Public Service Company of Colorado
- Savion LLC
- Staff of the Colorado Public Utilities Commission
- Szot Energy Services
- Tri-State Generation & Transmission Association
- Western Resource Advocates

Meetings were held on:

- October 29, 2020
- November 19, 2020
- December 10, 2020
- December 22, 2020
- January 14, 2021
- January 29, 2021
- February 28, 2021
- April 7. 2021
- May 13, 2021
- July 15, 2021
- August 19, 2021
- September 15, 2021

The 80x30TF provided a forum to develop transmission alternatives and recommendations related to the interconnecting significant renewable energy within ERZs 1, 2, 3, and 5 to achieve 80 percent carbon reduction from 2005 levels by 2030. Seven alternatives were studied in Phase I, with each alternative building upon or slightly modifying the previous one. The seven alternatives were:

- Alternative 1:
    - Double circuit 345 kV lines from Cheyenne Ridge to Pawnee to Fort St. Vrain
    - Double circuit 345 kV lines from Tundra to Harvest Mile
- Alternative 2:
    - Double circuit 345 kV lines from Cheyenne Ridge to Pawnee to Fort St. Vrain
    - Double circuit 345 kV lines from Tundra to Harvest Mile
    - Double circuit 345 kV lines from Tundra to Lamar
- Alternative 3:
    - Double circuit 345 kV lines from Cheyenne Ridge to Pawnee to Fort St. Vrain

    - Double circuit 345 kV lines from Tundra to Harvest Mile
    - Double circuit 345 kV lines from Tundra to Lamar
    - Double circuit 345 kV lines from Lamar to Cheyenne Ridge
- Alternative 4:
    - Double circuit 345 kV lines from Cheyenne Ridge to Pawnee to Fort St. Vrain
    - Double circuit 345 kV lines from Tundra to Harvest Mile
    - Single circuit 345 kV line from Tundra to Lamar
    - Single circuit 345 kV line from Lamar to Cheyenne Ridge
- Alternative 5:
    - Double circuit 345 kV lines from Cheyenne Ridge to Burlington to Story to Pawnee to Fort St. Vrain
    - Double circuit 345 kV lines from Tundra to Harvest Mile
    - Double circuit 345 kV lines from Tundra to Lamar
    - Double circuit 345 kV lines from Lamar to Cheyenne Ridge
- Alternative 6:
    - Double circuit 345 kV lines from Cheyenne Ridge to Story to Pawnee to Fort St. Vrain
    - Double circuit 345 kV lines from Tundra to Harvest Mile
    - Double circuit 345 kV lines from Tundra to Lamar
    - Double circuit 345 kV lines from Lamar to Cheyenne Ridge
- Alternative 7:
    - Double circuit 345 kV lines from Cheyenne Ridge to Story to Pawnee to Fort St. Vrain
    - Double circuit 345 kV lines from Tundra to Harvest Mile
    - Double circuit 345 kV lines from Tundra to Lamar 230 kV
    - Double circuit 345 kV lines from Lamar to Cheyenne Ridge

The results of the 80x30TF Phase I studies demonstrated that a 345 kV transmission expansion project capable of providing transmission access to the northeastern, eastern, and southern portions of Colorado, and interconnecting into the Company's existing Front Range transmission system, can accommodate the scale of future renewable generation necessary to meet 2030 carbon reduction goals. The identified transmission project (Alternative 3) would create a new Cheyenne Ridge area to Pawnee to Fort St. Vrain 345 kV double circuit line, a new Lamar area to Tundra to Harvest Mile 345 kV double circuit line, and a new Cheyenne Ridge to Lamar area 345 kV double circuit line to complete the 345kV loop, thus providing efficient and cost-effective transmission access to potential renewable generation located in ERZs 1, 2, 3 and 5. The identified project allows for modifications needed to add transmission interconnections to other Transmission Providers' facilities should they choose to utilize a portion of the project to meet their transmission access needs.

While Phase I studies primarily focused on Public Service's proposed alternatives to align with its scheduled 2021 ERP filing, the 80x30TF Phase II studies focused on stakeholder alternatives and/or additional studies requested by the task force members. After broad discussion with members pertaining to potential studies, the group focused on "balanced" generation portfolios, which assumed that the renewable generation resources are geographically spread around Colorado and are interconnected to the existing transmission system. The Phase II studies included generation portfolios submitted by members as well as portfolios created by Public Service – all without modeling any additional transmission included in Phase I. The key results and observations of the Phase II studies were that the number of Denver Metro area overloads are reduced when renewable resource locations are not confined to ERZs 1, 2, 3 and 5, but long generation tie-lines very likely would be required to interconnect them to the existing transmission, and many renewable resource locations assumed in the study have yet to be requested for interconnection by developers.

F. CCPG Responsible Energy Plan Task Force

In 2021, the REPTF, which was facilitated by Tri-State, evaluated transmission alternatives in eastern Colorado to accommodate new generation, improve reliability, and increase ability to deliver power across Tri-State's four-state service area.

In June 2021, the REPTF finalized a study scope and began evaluating transmission alternatives. The REPTF performed technical analyses of fifteen (15) alternatives that met one or more of the identified objectives and needs in eastern Colorado. Several other alternatives were considered, but not included in the technical analysis. The costs of the alternatives were based on indicative (conceptual 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, and the ability to meet all the objectives and needs. Other costs and benefits may be achieved but were not the focus of the REPTF studies. The REPTF provided an open stakeholder forum to analyze the costs and benefits of alternative transmission proposals in eastern Colorado.

The REPTF held seven regularly scheduled meetings since April 2021 to discuss study assumptions, study methodology, potential alternatives, cost estimates, and benefits. The REPTF participant list consisted of 59 stakeholders representing the following entities:

- Avangrid
- Basin Electric Power Cooperative
- Black Hills
- Buckyball Systems
- Colorado Springs Utilities
- Dietze and Davis, P.C.
- Enel Green Power
- Energy Strategies
- Grid Numerics
- Grid Resiliency Consulting
- Grid Strategies
- Independent Stakeholder
- Interwest Energy Alliance
- Invenergy
- Juwi
- National Renewable Solutions
- New Energy Consulting

- NextEra Energy
- Outshine Energy
- Platte River Power Authority
- SR3 Engineering
- State of Colorado – Office of the Utility Consumer Advocate
- State of Colorado – Public Utilities Commission
- Tri-State Generation & Transmission
- Western Resource Advocates
- Xcel Energy

Meetings were held on:

- April 12, 2021
- May 3, 2021
- June 2, 2021
- July 20, 2021
- August 12, 2021
- September 1, 2021
- September 27, 2021

The REPTF addressed stakeholder comments throughout the study process, which was documented in meeting notes. The REPTF evaluated numerous alternative proposals and agreed to perform technical analysis of the following fifteen (15) alternatives:

1. Advanced Transmission Technology (Power Flow Control) used in existing system.
2. Story – Burlington – Lamar 230 kV line; Boone – Comanche/Walsenburg ("ComWal"[10]) 230 kV line
3. Story – Burlington – Lamar 345 kV line; Boone – ComWal 230 kV line
4. Pawnee – Story – Burlington – Lamar 345 kV line; Boone – ComWal 230 kV line

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[10] "ComWal is a placeholder station name for the REPTF studies.

5. Pawnee – Story – Burlington – Lamar 345 kV line; Burlington – Cheyenne Ridge 345 kV line; Boone – ComWal 230 kV line
6. Pawnee – Story – Burlington – Lamar – Tundra 345 kV line; Burlington – Cheyenne Ridge 345 kV line; Boone – ComWal 230 kV line

6B. Pawnee – Story – Burlington – Lamar 345 kV line; Lamar – Boone 230 kV line Burlington – Cheyenne Ridge 345 kV line; Boone – ComWal 230 kV line

7. Story – Burlington 345 kV line; Burlington – Lamar 230 kV line; Boone – ComWal 230 kV line
8. Pawnee – Story – Burlington – Cheyenne Ridge 345 kV line; Burlington – Lamar 230 kV line; Boone – ComWal 230 kV line
9. Pawnee – Story – Cheyenne Ridge – Lamar 345 kV line; Boone– ComWal 230 kV line
10. Pawnee – Story – Cheyenne Ridge – Lamar – Tundra 345 kV line; Boone – ComWal 230 kV line
11. Rebuild Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV line; Story/Henry Lake ("StoHen" [11]) – Big Sandy – Boone – ComWal 230 kV line
12. Rebuild Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV line; Story – Big Sandy – Boone – ComWal 230 kV line
13. Rebuild Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV line; Story – Big Sandy 230 kV line; Boone – ComWal 230 kV line
14. Rebuild Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV line; Story – Big Sandy 230 kV line; Burlington – Lamar 230 kV line; Boone – ComWal 230 kV line

Sensitivity studies were performed on select alternatives with Public Service's proposed Colorado's Power Pathway project to determine any potential interactions, and separately with Advanced Transmission Technologies (Power Flow Control) to determine potential to enhance performance of alternatives. The REPTF study report was finalized on September 27, 2021, and accepted by CCPG on December 16, 2021. All supporting documentation including meeting agendas, presentations, and notes are accessible from the CCPG – Responsible Energy Plan Task Force website located at:

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

[11] "StoHen is a placeholder station name for the REPTF studies.

G. CCPG 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. Energy Storage and Non-Wire alternatives Working Group ("ESWG") will continue to focus on the integration of energy storage resources and non-wire alternatives into the bulk power system. ESWG will consider all forms of energy storage and will focus on transmission functions of energy storage technologies and performance, economics, integration into system models, and other aspects associated with the application of energy storage systems. The ESWG's recommendations and evaluations will be made available to the CCPG and stakeholders.

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 approved its charter on August 13, 2020. The charter is available at this link: https://doc.westconnect.com/Documents.aspx?NID=19147&dl=1

The ESWG held two meetings in 2020, the first on January 23, 2020, and subsequently on August 13, 2020. The ESWG has met three times during the 2021 calendar year. The dates are included below.

- April 1, 2021
- May 6, 2021
- June 3, 2021

Meeting notices for the above dates were delivered via the CCPG Stakeholder Distribution List, as well as posted to the WestConnect Calendar.

During the April 1, 2021, meeting, the working group established a scope of work that was developed into three parts. Part One focuses on a review of relevant rules and standards pertaining to energy storage and non-wire alternatives. On May 6, 2021, a presentation was given regarding the applicable rules and standards as a level set for all members and stakeholders. Part Two of the scope targets technical information gathering and sharing among the members and stakeholders. On June 3, 2021, ESWG hosted a presentation by American Transmission Company ("ATC") titled "Energy Storage as a Transmission Asset in MISO". ATC shared their experience on development and implementation of an energy storage as a transmission asset. Part Three of the scope of work outlines a set of deliverables that will encompass the working group's efforts. An informative guide will be developed as a method of sharing all the group's relevant knowledge on the various technologies and will be updated continuously as new information is reviewed. Further, the group will seek to develop an evaluation matrix and flow chart to assist those seeking alternatives to transmission projects.

All ESWG meeting materials and presentations can be found on the WestConnect website at this link: https://doc.westconnect.com/Documents.aspx?NID=19141

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 O.

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 Responsible Energy Plan Task Force in its 2021 study report. The study focused, among other things, on mitigating operational and maintenance challenges in eastern Colorado. The REPTF proposed and evaluated several potential transmission projects to improve system reliability and maintenance of the transmission system in eastern Colorado. More information on this study can be found in the Responsible Energy Plan Task Force Study Report included in Appendix O.

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 80x30 Task Force and REPTF each explicitly considered the ability of transmission alternatives to allow the injection and export of new generation resources, and ability to align with longer-term transmission strategies. Generation injection capability analyses was performed in each task force to determine relative strength of transmission alternatives. This type of analysis is a common way to consider the relative ability of various transmission alternatives to accommodate new generation resources. The 80x30 Task Force Study considered the ability of each alternative to allow new resources out of the ERZs 1, 2, 3, and 5 to be reliably delivered to the Front Range. Both task forces evaluated transmission alternatives that would provide a more robust transmission system to allow for long-term import/export of resources to/from Colorado. More information on the Phase I Transmission Report, completed in 2021, for the 80x30 Task Force can be found in Appendix P.

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 electric system ("BES"). 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 BES 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 BES.

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.org/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 N-130 – N-132 of the Black Hills Open Access Transmission Tariff ("OATT") Attachment K Methodology, Criteria, and Process Business Practices document, available in Appendix N.

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 Utility 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 10 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 10, 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 O.

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 P.

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 2022 Plan complies with all applicable NERC and WECC reliability standards and other applicable legal and regulatory requirements. These requirements are the renewable energy standards ("RES") and resource adequacy. Both requirements are included in Black Hills' ERP proceedings at the Commission.

Black Hills' currently effective ERP was approved by the Commission in Proceeding No. 16A-0436E.[12] Resource planning covers a Resource Acquisition Period of seven years from January 2016 through December 2022. RES compliance covers a period of 2018 through 2022. RES compliance covers the Company's acquisition of renewable resources from on-site solar photovoltaic ("PV") and community solar garden ("CSG") installations.

Black Hills' ERP was amended in Commission Proceeding No. 19A-0660E for the acquisition of 200 MW of renewable energy and energy storage through a competitive solicitation. Recommended Decision R20-0647 was mailed on September 3, 2020, granting a settlement agreement to acquire Bid 128-03 (the Preferred Bid) and proceed with negotiating and executing a Power Purchase Agreement ("PPA"). Bid 128-03 (Turkey Creek Project) is a 200 MW solar project. The PPA was fully executed on February 19, 2021.

Black Hills filed a Petition for Waivers and Variances in Commission Proceeding No. 21V-0342E on July 16, 2021, which the Commission granted. The petition extended the filing of the Company's next ERP application to March 31, 2022. The ERP application will provide a CEP pursuant Senate Bill 19-236.

[12] On January 17, 2017, Recommended Decision No. R17-0039 was entered for ERP Phase I and became a decision of the Commission by operation of law. Phase I is a determination of resource need. On June 14, 2018, Commission Decision No. C18-0426 was entered for ERP Phase II. Phase II approves resource selection.

2. Tri-State Legal Requirements

Tri-State's 2022 Ten-Year Transmission Plan complies with all applicable NERC and WECC reliability standards, as well as other applicable legal and regulatory requirements, including those associated with Tri-State's and its Colorado Utility Members' compliance with the Colorado RES and Colorado's GHG emission reduction goals.

Beginning in 2020 and continuing thereafter, the Colorado RES requires that 10 percent of Tri-State's Utility Members' retail electricity sales be served by eligible energy resources.[13] 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 Utility Members at wholesale from eligible energy resources in the year 2020 and thereafter. As the wholesale power provider for its Utility Members, Tri-State's 2022 Plan is developed to ensure that the necessary transmission system capabilities will be in place to meet both its Colorado Utility Members' 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 at:

https://www.tristategt.org/resource-planning

Tri-State may be subject to federal and state regulations related to carbon dioxide and GHG emission reductions associated with its generation resources. Colorado House Bill 19-1261 sets forth statewide goals for increasing the use of renewable energy and reducing statewide GHG emissions by 2050. As of the date of

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[13] For Tri-State's Utility Members that serve 100,000 or more meters, the Colorado RES requires that, as of 2020 and thereafter, 20 percent of the Utility Member's retail electricity sales be served by eligible energy resources. As of June 2021, United Power became Tri-State's only Utility Member surpassing this threshold.

this 10-Year Transmission Plan, no state regulations have been promulgated pursuant to HB19-1261 that establish GHG emission reduction requirements specifically applicable to the electric utility industry. However, as a practical matter, the GHG emission reduction goals of HB19-1261 work in concert with the CEP requirements of SB19-236 and the ERP requirements of HB21-1266. SB19-236 requires defined qualifying retail utilities to submit to the Commission a CEP that will achieve an 80 percent reduction, from 2005 levels, in carbon dioxide emissions associated with its electricity sales and that makes progress toward a 100 percent clean energy goal by 2050. SB19-236's CEP requirements do not apply to Tri-State; nevertheless, Tri-State's 2020 Electric Resource Plan submitted to the Commission on December 1, 2020, (Proceeding No. 20A-0528E) includes a preferred plan designed to achieve the same emission reductions that would be required under a Clean Energy Plan.[14] Tri-State's 2020 Electric Resource Plan also complies with the ERP requirements of HB21-1266, which became law after Tri-State's ERP was filed.

In addition to Colorado's RES and GHG emission reduction requirements and goals, Tri-State also notes that, since it operates an interconnected, interstate transmission system, its transmission system may be impacted as a result of compliance with federal renewable energy and GHG emission reduction requirements, as well as carbon dioxide emission reduction plans enacted in other states in which Tri-State operates.

3. Public Service Legal Requirements

Public Service's 2022 Plan complies with its currently operative ERP, approved by the Commission in Proceeding 16A-0396E in its Phase II decision, C18-0761.[15] A new, 2021 Clean Energy Plan and Electric Resource Plan is pending before the

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[14] While not a legal requirement *per se*, Tri-State also has considered the policy goals set forth in Governor Jared Polis's "Roadmap to 100% Renewable Energy by 2040 and Bold Climate Action" issued in 2019 and the Colorado "Greenhouse Gas Pollution Reduction Roadmap" issued in 2020.

[15] As amended in Proceeding No. 19A-0530E.

Commission in Proceeding No. 21A-0414E. 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 2022 Plan additionally complies with its currently operative Renewable Energy Standard Compliance Plan ("RE Compliance Plan") approved by the Commission in Proceeding No. 19A-0369E. A new RE Compliance Plan is pending before the Commission in Proceeding No. 21A-0625EG.

Information on Public Service compliance with Renewable Energy Standard 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.

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 N of this document. Additional information concerning Black Hills' FERC Order No. 890 processes also can be found in Appendix N.

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 is available on Tri-State's OASIS and can be updated periodically. The most current version at the time of Attachment K is located in Appendix O.

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.transmission.xcelenergy.com/staticfiles/microsites/Transmission/Files/PDF/OASIS-OATT/7-26-2021_Xcel%20Energy%20OATT_Current%20Tariff_ER21-1652.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 three planning "regions"[16] within WECC established for regional transmission planning to comply with Order 1000. Public Service, Tri-State, and Black Hills have designated WestConnect as their Order 1000 compliant planning regions. The WestConnect planning process is described in Black Hills', Tri-State's, and Public Service's OATTs (Attachment K, 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.

[16] The other two regions are Northern Grid and the California Independent System Operator.

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

VIII. 10-Year Transmission Plan Supporting Documentation

A. Background Context Concerning Models and Model Outputs

Though not set forth in Commission rule, the Commission has in past plans requested supplemental information concerning the models used and copies of the modeling outputs.[17] In the interests of transparency and addressing this issue from the outset, the Joint Utilities reiterate that they cannot provide the models used in the Joint 10-Year Transmission Plan and 20-Year Conceptual Scenario, as they are considered 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.

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 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

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

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 five-year cases
    - Reflecting expected system conditions five 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 five- 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 generally will 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 nondisclosure 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 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.

B. Methodology, Criteria, & Assumptions

1. Facility Ratings (FAC-008-5)

NERC Reliability Standard FAC-008-5 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-008-5 also requires transmission and generation owners to establish facility ratings per the methodology established through FAC-008-5. 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 Coordinator(s), Transmission Planner(s), Transmission Owner(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 WECC Data Preparation Manual for Interconnection-wide Cases ("Data Preparation Manual").

a. Black Hills Ratings

Documentation of Black Hills' FAC-008-5 methodology is available in Appendix N.

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 Standards Bulletin at the time of this filing can be found in Appendix O.

c. Public Service Ratings

Documentation of Public Service FAC-008-005 methodology can be found in Appendix P.

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

The Companies utilize transmission system power flow and transient stability modeling data prepared by the WECC. Through its annual study program, WECC facilitates the preparation of at least 10 study models per year. The models represent a variety of system conditions out to a 10-year planning horizon. WECC does not develop study models beyond the 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 is one of the coordinators of 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 topology, 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.

The Companies provide instructions for accessing WECC base cases in Appendix Q.

C. 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 N of this report.

b. Tri-State Forecasts

General load forecast information is available on Tri-State's OASIS by clicking on "ATC Information" and then "Load Forecast Descriptive Statement". The Load Forecast Descriptive Statement available at the time of this filing is located in Appendix O.

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 2020 load forecast data. Base forecast data for these plans is available in Tri-State's Resource Plan/Electric Resource Plan and Electric Resource Plan Annual Progress Reports available at:

https://www.tristategt.org/resource-planning

c. Public Service Forecasts

The load forecast used in this filing is the March 2021 PSCo Load Forecast, which was provided publicly in the Company's 2021 ERP and CEP filing. In addition to PSCo native load forecast, Public Service receives load forecast from its network customers, which it incorporates into the overall PSCo network load forecast. The forecasted PSCo network load is then allocated on a substation-by-substation basis to load buses in the transmission planning model, based on historical trend. Additional information on allocation of forecasted load is included in Appendix P.

2. Demand-Side Management

The effects of 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 N 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 Utility Members' 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 Utility 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 2020 ERP.

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 P.

D. Generation and Dispatch Assumptions

Generator and associated equipment models are typically included in the WECC Annual Base Case[18] 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

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[18] The Companies are providing instructions for accessing WECC Base Case information in Appendix Q.

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 N) 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, Kit Carson Electric Cooperative (“KCEC”), Delta-Montrose Electric Association (“DMEA”), 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 Generation Dispatch Assumptions

Public Service transmission planning models, to a certain degree, reflect economic generation dispatch to serve the forecasted system load at various seasonal demand levels – peak, off-peak and light load conditions. Assumptions used for dispatching generators in planning models based on their fuel type are noted below and available on PSCo OASIS under External BPM for Large Generator Interconnection Procedures.

- Renewable generation, such as wind or wind plus battery storage hybrid generation facilities are dispatched at ~80% of nameplate rating. The solar or solar plus battery storage hybrid generation facilities are dispatched at ~85% of nameplate rating. Standalone battery storage facilities are modeled at ~90% of nameplate rating.
- Gas-fired combustion turbine generators are typically dispatched at ~90% of nameplate for peak load conditions and may be off-line (zero MW/MVAR output) for light load conditions when renewable generation adequately meets the load demand.
- Coal-fired and combined cycle generators are typically dispatched at or near full output (~100% of nameplate) for all the load conditions. These units are typically considered as "base load" generation – that is, they are generally the first to be committed and last to be decommitted.
- Pumped sstorage hhydro generators are dispatched appropriately – in generating mode during peak and off-peak load hours and in pumping mode during light load hours.

E. 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 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

Documentation of Public Service FAC-010-3 methodology can be found in Appendix P.

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

Available Transmission System Capability Methodology is available and posted per NERC Standard MOD-001-1a at NERC's website.

a. Black Hills TTC

Black Hills utilizes the Rated System Path Methodology for determining Total Transfer Capability ("TTC") and 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 N.

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 associated 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, by clicking on "ATC Information" and then "Available Transfer Capability Implementation Document (ATCID)".

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 O.

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 is updated periodically and the most recent version can be found in Appendix P.

3. Capacity Benefit Margin (MOD-004-1)

Capacity Benefit Margin ("CBM") methodology is available and posted per NERC Standard MOD-004-1.

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 N.

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 O.

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 is updated periodically and the most recent version can be found in Appendix P.

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 N.

b. Tri-State TRM

The TRMID for Tri-State is available on Tri-State's OASIS, by clicking on "ATC Information" and then "Transmission Reliability Margin Implementation Document (TRMID)".

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

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 is updated periodically and the most recent version is located in Appendix P.

F. Status of Upgrades

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

G. 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://regplanning.westconnect.com/ccpg.htm

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 by clicking on "Operations" and then viewing

"Transmission planning" and "Transmission projects" sections. Generator interconnection, transmission service request, and other OATT study reports related to Tri-State's transmission system are posted on Tri-State's OASIS at:

https://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

H. In-Service Dates

Information concerning the expected in-service date for each utility's facilities identified in the 2022 Plan and the entities responsible for constructing and financing each facility is contained in Table 1, Section III and Appendices A-I.

I. 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 N.

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 N. 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 2020 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

Tri-State facilitates priority local economic planning studies for its transmission system, pursuant to the procedures in its OATT Attachment K. Regional economic planning studies are performed by WestConnect. 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 www.wecc.org). 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.

2022 CPUC Rule 3627 Appendices

Appendix A: Colorado Transmission Maps
Appendix B: Denver-Metro Transmission Map
Appendix C: Black Hills Energy Transmission Map
Appendix D: Black Hills Energy Projects
Appendix E: Tri-State Generation and Transmission Association Projects
Appendix F: Public Service Company of Colorado Projects
Appendix G: Colorado Springs Utilities Projects
Appendix H: Platte River Power Authority Projects
Appendix I: Western Area Power Administration - RMR Projects
Appendix J: CCPG Stakeholder Process
Appendix K: Public Service Company CCPG Stakeholder Comments
Appendix L: Black Hills CCPG Stakeholder Comments
Appendix M: Tri-State CCPG Stakeholder Comments
Appendix N: Black Hills Supporting Documents
Appendix O: Tri-State Supporting Documents
Appendix P: Public Service Company Supporting Documents
Appendix Q: Instructions for Accessing Model Data