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, 2024

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ACRONYMS AND ABBREVIATIONS

2024 Plan	2024 10-Year Transmission Plan for the State of Colorado	1
AAR	Ambient-Adjusted Ratings	30
AC	Alternating Current	30
ACSR	Aluminum Conductor Steel Reinformed	33
ACSS	Aluminum Conductor Steel Supported	33
ARPA	Arkansas River Power Authority	153
ATCID	ATC Implementation Document	159
ATTs	Advanced Transmission Technologies	29
BAA	Balancing Authority Area	58
BE	Beneficial Electrification	21
BES	Bulk Electric System	17, 128
BHCT	Black Hills Colorado Transmission	91
Black Hills	Black Hills Colorado Electric, LLC, d/b/a Black Hills Energy	1
CBM	Capacity Benefit Margin	160
CBMID	Capacity Benefit Margin Implementation Document	160
CCPG	Colorado Coordinated Planning Group	17
CEII	Critical Energy Infrastructure Information	37
CEO	Colorado Energy Office	23
CEPs	Clean Energy Plans	21
Commission or CPUC	Colorado Public Utilities Commission	1
CPCN	Certificate of Public Convenience and Necessity	22, 43
CSG	Community Solar Garden	131
CSU	Colorado Springs Utilities	86
Data Preparation Manual	Data Preparation Manual for Interconnection-wide Cases	145
DC	Direct Current	30
DER	Distributed Energy Resources	150
DLR	Dynamic Line Ratings	29
DMEA	Delta-Montrose Electric Association	153
DOLA	Department of Local Affairs	29
DSC	Distributed Series Compensator	32
DSM	Demand Side Management	150
EAC	Estimate at Completion	64
EPAct	Energy Policy Act	128
ERP	Electric Resource Plan	21

ERZs	Energy Resource Zones	58
ESWG	Energy Storage and Non-Wire Alternatives Working Group	121
EVF	Electric Vehicle	25
EVs	Electric Vehicles	150
FACTS	Flexible Alternating Current Transmission Systems	31
FERC	Federal Energy Regulatory Commission	3
FPA	Federal Power Act	128
GDT Project	Greenwood and Denver Terminal	64
HB	House Bill	21
HS	Heavy Summer	91
HTLS	High Temperature, Low Sag	33
HVDC	High Voltage Direct Current	54
IIJA	Infrastructure Investment and Jobs Act of 2021	23
KCEA	K.C. Electric Association	50
KCEC	Kit Carson Electric Cooperative	153
L&R	Load and Resource	147
LTC	Load Tap-Changing	92
LTP	Local Transmission Plan	101
MW	Megawatts	150
NCAP	Northern Colorado Area Plan	98, 109
NECO	Northeastern Colorado	69
NECO Subcommittee	Northeastern Colorado Subcommittee	80
NERC	North American Electric Reliability Corporation	20
NERC TPL	NERC Transmission Planning	143
OASIS	Open Access Same-Time Information System	91
OATT	Open Access Transmission Tariff	56, 129, 133
Order 1000	FERC Order No. 1000 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities	17
PA	Planning Authority	157
PAR	Phase Angle Regulator	31
Pathway Project	Power Pathway Project	97
PNM	Public Service Company of New Mexico	153
POI	Point of Interconnection	69
PPA	Purchase Power Agreement	38
PRPA	Platte River Power Authority	86
PST	Phase-Shifting Transformer	31
Public Service	Public Service Company of Colorado	1

PV	Photovoltaic	131
RAS	Remedial Action Schemes	31
RE Compliance Plan	Renewable Energy Standard Compliance Plan	133
RES	Renewable Energy Standard	22
Review Group	Ad-Hoc Review Group	115
RFP	Request for Proposals	38
ROW	Rights-of-Way	29
RTO	Regional Transmission Organization	16
SB07-100	Colorado Senate Bill 07-100	88
SLV	San Luis Valley	51
SLV Subcommittee	San Luis Valley Subcommittee	99
SLVTF	San Luis Valley Task Force	81
SOL	System Operating Limits	157
SPS	Southwestern Public Service Company	54
SSSC	Static Synchronous Series Compensators	32
Staff	Staff of the Colorado Public Utilities Commission	83
STATCOM	Static Synchronous Compensators	32
SVC	Static VAR Compensators	32
TC Colorado	TC Colorado Solar	38
TCPC	Transmission Coordination and Planning Committee	91
TPs	Colorado Transmission Providers	1
Tri-State	Tri-State Generation and Transmission Association, Inc.	1
TRMID	Transmission Reliability Margin Implementation Document	161
TTC	Total Transfer Capacity	158
UCA	Utility Consumer Advocate	28, 83
UPFC	Unified Power Flow Controller	33
WAPA	Western Area Power Administration	68
WECC	Western Electricity Coordinating Council	17, 91
WECC TPL	WECC Transmission Planning	128

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. 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 2024 10-Year Transmission Plan for the State of Colorado ("2024 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 seventh 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 2024 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 2024 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 2024 Plan and the individual transmission projects included in the 2024 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 2024 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 have effectively 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 2024 Plan and could result in changes to in-service dates or project scopes.

Public policy initiatives, such as recent and future federal, state, and local mandates, also may impact the 2024 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 2024 Plan identifies 101 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 2024 Plan[1]

Map #	Project Name	In-Svc	Cost ($ millions)	BH	TS	PS	Other	Purpose
1	Avery Substation	2022	$12.10			√		L
2	CEPP Voltage/Reactive Support	2022	$67.30			√		G
3	Comanche Substation – Generation Interconnect (CEPP bid 077)	2022	$1.70			√		G
4	Del Camino-Slater 115kV Line Uprate	2022	$1.40		√			L,R

[1] 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.

5	Greenwood-Denver Terminal 230kV Line	2022	$102.70			√		G,L,R
6	High Point Distribution Substation	2022	$18.90			√		L
7	Mirasol (formerly Badger Hills) Switching Station (CEPP Bid X647)	2022	$22.80			√		G
8	Tundra (CEPP Switching Station Bid X645)	2022	$21.90			√		G
9	Bluestone Valley Substation Phase 2	2023	$18.60			√		L
10	North System Improvements	2023	$11.00				CSU	R
11	Fuller Transformer	2024	$14.60				CSU	L
12	Horizon Substation	2024	$47.40				CSU	L
13	Kettle Creek Transformer	2024	$2.80				CSU	L
14	Nixon-Kelker 230kV Line Uprate	2024	$0.20				CSU	R
15	Pike Solar	2024	$6.70				CSU	G
16	Cahone Line Bay Addition	2024	$0.72		√			G
17	Garnet Mesa Solar Interconnect	2024	$2.40		√			G
18	Valent 230 kV Switching Station	2024	$6.30		√			G
19	Fox Run Substation Expansion	2024	$15.10		√			L,R
20	Pueblo West 115kV Distribution Sub	2024	$5.40	√				R

21	West Station to Hogback 115 kV Transmission Project AKA West Station to Canon City	2024	$25.80	√				L,R
22	Canon West 230/115 kV XFMR Replacement	2024	$4	√				L
23	BHCT G29 200 MW PV/ES Interconnection	2024	$6.20	√				G
24	Ault-Cloverly 230/115 kV Transmission	2024	$123.50			√		L,R
25	Black Hollow Sun (BHS) Project	2024	$20.00				PRPA	G
26	Flying Horse Flow Mitigation	2024	$3.40			√	CSU	R
27	Metro Water Recovery Substation (100% customer funded)	2024	$16.00			√		L
28	Slater Double Circuit Conversion	2025	$7.20		√			L,R
29	Cross Point 230/69kV Delivery Point	2025	$12.00		√			L,R
30	Burlington-Lamar 230 kV Line	2025	$89.00		√			G,L,R
31	Main Switch Bay Addition	2025	$2.80		√			G
32	Milk Creek Switching Station	2025	$13.30		√			G
33	Fuller BESS	2025	$13.00				CSU	G

34	Midway Substation – Generation Interconnect (CEPP bid 056)	2025	$1.70			√		G
35	Stagecoach Switching Station	2025	TBD			√		G
36	Uprate Substations on Circuit 3006 Poncha West and San Luis Valley	2025	TBD			√		R
37	Uprate Substations on Circuit 9811 Poncha Junction and San Luis Valley	2025	TBD			√		R
38	Flying Horse Transformer	2026	$8.30				CSU	L
39	Claremont Transformer	2026	$15.80				CSU	L
40	Rolling Meadows 115 kV Delivery Point	2026	$7.90		√			L
41	Boone – Huckleberry 230 kV Line	2026	$37.30		√			G,L,R
42	Daniels Park to Greenwood Circuit 5707 Uprate	2026	TBD			√		R
43	Daniels Park to Greenwood Circuit 5111 Uprate	2026	TBD			√		R
44	Greenwood Substation Bus Tie Uprate	2026	TBD			√		R

45	Kestrel (formerly Project Bronco) Distribution Substation (100% customer funded)	2026	$28.1			√		L
46	Leetsdale to University 115 kV Circuit 9338 Uprate	2026	TBD			√		R
47	Midway Substation 230 kV Bus Uprate	2026	TBD			√		R
48	San Luis Valley 115 kV Circuit 9431 Uprate	2026	TBD			√		R
49	Tollgate Substation Load Shift	2026	TBD			√		R
50	Poder Distribution Substation	2026	$5.9			√		L
51	230 kV Circuit 5165 In and Out of Harvest Mile	2027	TBD			√		R
52	Leetsdale – Elati 230 kV Circuit 5283 Underground Transmission Line Upgrade	2027	TBD			√		R
53	Avon-Gilman 115 kV Transmission	2027	TBD			√		R
54	Barker Distribution Substation	2027	TBD			√		L
55	Colorado’s Power Pathway (With Optional Segment)	2027	$1,685 ($TBD)			√		G, R

56	Fort Morgan Capacitor Bank Replacement Project	2027	$2.00				WAPA	R
57	South System Improvements	2027	$71.00				CSU	L,R
58	Havana to Chambers Circuits 9543 and 9544 Uprate	2027	TBD			√		R
59	Midway Substation 230/115 kV Transformer Replacement	2027	TBD			√		R
60	Sandstone Switching Station	2027	TBD			√		R
61	Central System Improvements	2027	$134.00				CSU	R
62	Alamosa to Mosca to San Luis Valley 69 kV Circuits 6935/6936 Uprate	2028	TBD			√		R
63	Arapahoe 115 kV Bus Uprate and Second 230/115 kV Transformer	2028	TBD			√		R
64	Big Sandy – Badger Creek 230 kV Line	2028	$65.60		√			G,L,R
65	Big Sandy – Burlington 230 kV Line Uprate	2028	$7.00		√			G, R
66	Malta to Poncha Junction Circuit 9255 Uprate	2028	TBD			√		R

67	New 115 kV Line San Luis Valley to Alamosa Terminal	2028	TBD			√		R
68	Uprate Substations on Circuit 5057	2028	TBD			√		R
69	Capitol Hill to Denver Terminal 115 kV Circuit 9007 Uprate	2029	TBD			√		R
70	Chambers Third 230/115 kV Transformer	2029	TBD			√		R
71	Cherokee to Broomfield 115 kV Circuits 9055/9558/9464 Uprate	2029	TBD			√		R
72	Daniels Park Fourth Transformer	2029	TBD			√		R
73	Leetsdale to Harrison 115 kV Circuit 9955 Uprate	2029	TBD			√		R
74	Smoky Hill Third Transformer	2029	TBD			√		R
75	New Double Circuit 230 kV Line from Harvest Mile – Chambers – Sandown – Cherokee	2030	TBD			√		R
76	Phase Shifting Transformer on Missile Site to Daniels Park 345 kV Circuit 7109	2030	TBD			√		R

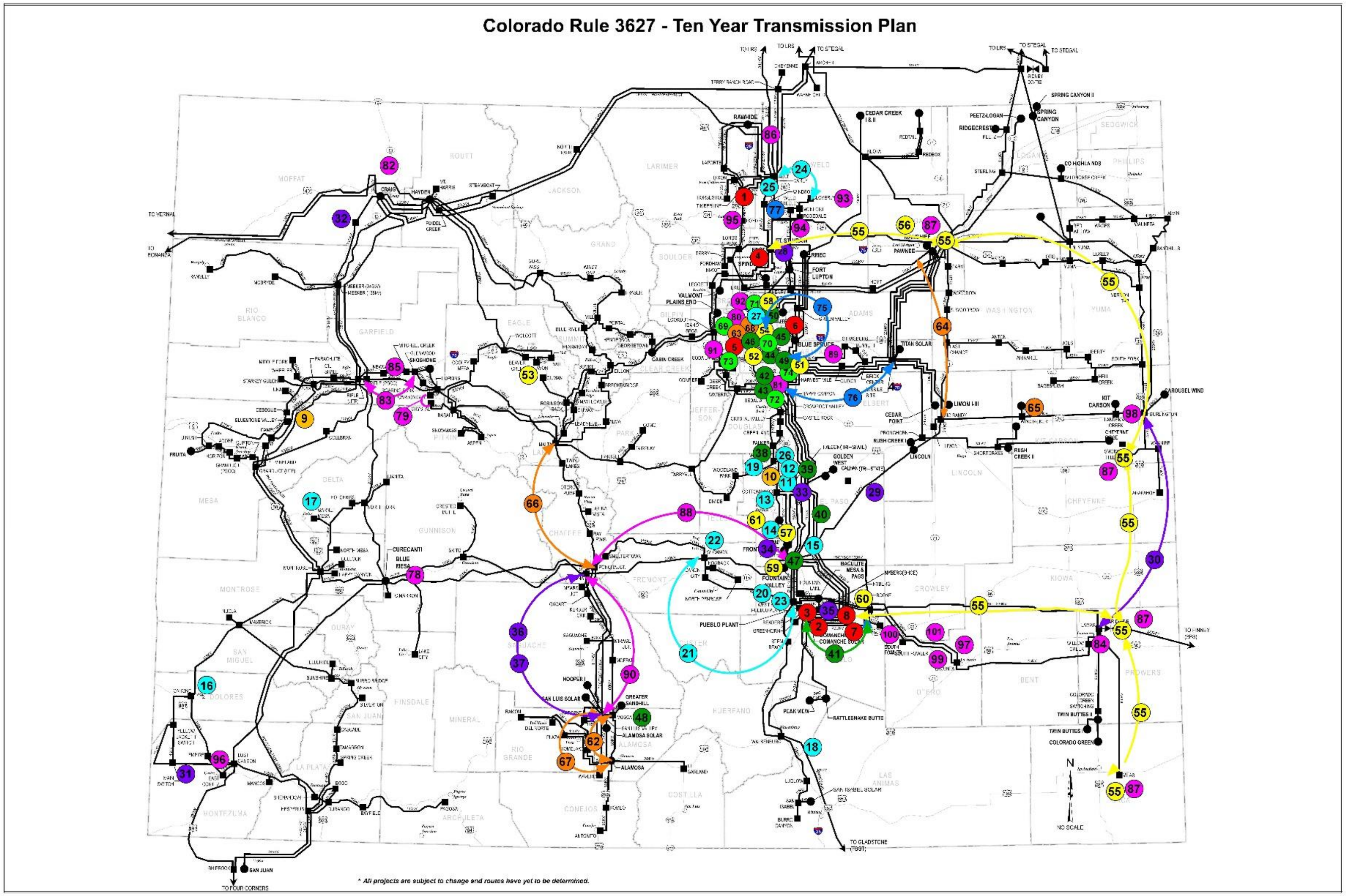
77	Weld KV1A Replacement and Breaker and Half Project	2030	$13.80				WAPA	R, L
78	Blue Mesa Reactor and Transformer	2032	$9.70				WAPA	R
79	Carbondale – Crystal 115 kV Transmission	TBD	TBD			√		R, L
80	Denver Metro Area Upgrades	TBD	TBD			√		G, R
81	Dove Valley Distribution Substation	TBD	TBD			√		L
82	Gateway South – Craig/Hayden Area Transmission	TBD	TBD			√		R
83	Glenwood-Rifle 115 kV Transmission	TBD	TBD			√		L,R
84	Lamar DC Tie Replacement	TBD	TBD			√		G,L,R
85	New Castle Distribution Substation	TBD	TBD			√		L
86	Northern Colorado Transmission	TBD	TBD			√		R
87	Pathway Voltage Control/Support	TBD	TBD			√		R
88	Poncha – Front Range 230 kV	TBD	TBD			√		G
89	Sandy Creek Distribution Substation	TBD	TBD			√		L

90	San Luis Valley-Poncha 230 kV Line #2[2]	TBD	TBD		√	√		R,G
91	Solterra Distribution Substation	TBD	TBD			√		L
92	Superior Distribution Substation	TBD	TBD			√		L
93	Weld County Transmission Expansion	TBD	TBD			√		G,R
94	Weld-Rosedale-Box Elder-Ennis 230/115 kV	TBD	TBD			√		L,R
95	Wilson Distribution Substation	TBD	TBD			√		L
96	Lost Canyon-Main Switch 115 kV Line	TBD	TBD		√			L,R
97	La Junta 115 kV Tie	TBD	TBD		√			L,R
98	Burlington-Burlington (KCEA) Rebuild	TBD	TBD		√			R
99	Rocky Ford 69-115 kV Conversion Phase I	TBD	TBD	√				R,L
100	Rocky Ford 69-115 kV Conversion Phase II	TBD	TBD	√				R,L
101	Rocky Ford 69-115 kV Conversion Phase III	TBD	TBD	√				R,L

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

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

Figure 1. Statewide map of transmission projects in the 2024 Plan



2022

1. Avery Substation (PSCo)
2. CEPP Voltage/Reactive Support (PSCo)
3. Comanche Substation - Generation Interconnection (CEPP Bid 077) (PSCo)
4. Del Camino - Slater 115kV Line Uprate (Tri-State)
5. Greenwood - Denver Terminal 230kV Line (PSCo)
6. High Point Distribution Substation (PSCo)
7. Mirasol (Formerly Badger Hills) Switching Station (CEP Bid X647)(PSCo)
8. Tundra (Formerly CEPP Switching Station Bid X645) (PSCo)

2023

9. Bluestone Valley Substation Phase-2 (PSCo)
10. North System Improvements (CSU)

2024

11. Fuller Transformer (New, CSU)
12. Horizon Substation (New, CSU)
13. Kettle Creek Transformer (New, CSU)
14. Nixon - Kelker 230kV Line Uprate (CSU)
15. Pike Solar and BESS (New, CSU)
16. Cahone Line Bay Addition (New, Tri-State)
17. Garnet Mesa Solar Interconnect (New, Tri-State)
18. Valent 230 kV Switching Station (New, Tri-State)
19. Fox Run Substation Expansion (New, Tri-State)
20. Pueblo West 115kV Distribution Sub (New, BHCE)
21. West Station - Hogback 115kV Transmission Project AKA West Station to Canyon City (BHCE)
22. Canyon West 230/115 kV Transformer Replacement (New, BHCE)
23. BHCT G29 200 MW PV/ES Interconnection (New, BHCE)
24. Ault - Cloverly 230/115kV Transmission Project (PSCo)
25. Black Hollow Sun (BHA) Project (PRPA)
26. Flying Horse Flow Mitigation (CSU)
27. Metro Water Recovery Substation (100% customer funded) (New,PSCo)

2025

28. Slater Double Circuit Conversion (New, Tri-State)
29. Cross Point 230/69 Kv Delivery Point (New, Tri-State)
30. Burlington - Lamar 230kV (Tri-State)
31. Main Switch Bay Addition (New, Tri-State)
32. Milk Creek Switching Station (New, Tri-State)
33. Fuller BESS (New, CSU)
34. Midway Substation - Generation Interconnection (CEPP Bid 056) (New, PSCo)
35. Stagecoach Switching Station (New, PSCo)
36. Uprate Substations on curcuit 3006 Poncha West and San Luis Valley (New, PSCo)
37. Uprate Substations on curcuit 9811 Poncha Junction and San Luis Valley (New, PSCo)

2026

38. Flying Horse Transformer (CSU)
39. Claremont Transformer (New, CSU)
40. Rolling Meadows 115 kV Delivery Point (New, Tri-State)
41. Boone - Huckleberry 230kV Line (New, TSGT)
42. Daniels Park to Greenwood Circuit 5707 Uprate (New, PSCo)
43. Daniels Park to Greenwood Circuit 5111 Uprate (New, PSCo)
44. Greenwood Substation Bus Tie Uprate (New, PSCo)
45. Kestrel (formerly Project Bronco) Distribution Substation (100% customer funded) (New, PSCo)
46. Leetsdale to University 115 kV Circuit 9338 Uprate (New, PSCo)
47. Midway Substation 230 kV Bus Uprate (New, PSCo)
48. San Luis Valley 115 kV Circuit 9431 Uprate (New, PSCo)
49. Tollgate Substation Load Shift (New, PSCo)
50. Poder Distribution Substation (PSCo)

2027

51. 230 kV Circuit 5165 In and Out of Harvest Mile (New, PSCo)
52. Leetsdale - Elati 230 kV Circuit 5283 Undergroung Transmission Line Upgrade (New, PSCo)
53. Avon - Gilman 115kV Transmission (PSCo)
54. Barker Distribution Substation (PSCo)
55. Colorado's Power Pathway (With Optional Segment) (PSCo)
56. Two Basins Relocation Project (PSCo)
57. South System Improvements (New, CSU)
58. Havana to Chambers Circuits 9543 and 9544 Uprate (New, PSCo)
59. Midway Substation 230/115 kV Transformer Replacement (New, PSCo)
60. Sandstone switching Station (New, PSCo)
61. Central System Imrovements (CSU)

2028

62. Alamosa to Mosca to San Luis Valley 69 kV Circuits 6935/6936 Uprate (New, PSCo)
63. Arapahoe 115 kV Bus Uprate and Second 230/115 kV Transformer (New, PSCo)
64. Big Sandy - Badger Creek (Tri-State)
65. Big Sandy - Burlington 230kV Line Update (Tri-State)
66. Malta to Poncha Junction Circuit 9255 Uprate (New, PSCo)
67. New 115 kV Line San Luis Valley to Alamosa Terminal (New, PSCo)
68. Uprate Substations on Circuit 5057 (New, PSCo)

2029

69. Capitol Hill to Denver Terminal 115 kV Circuit 9007 Uprate (New, PSCo)
70. Chambers Third 230/115 kV Transformer (New, PSCo)
71. Cherokee to Broomfield 115 kV Circuits 9055/9558/9464 Uprate (New, PSCo)
72. Daniels Park Fourth Transformer (New, PSCo)
73. Leetsdale to Harrison 115 kV Circuit 9955 (New, PSCo)
74. Smoky Hill Third Transformer (New, PSCo)

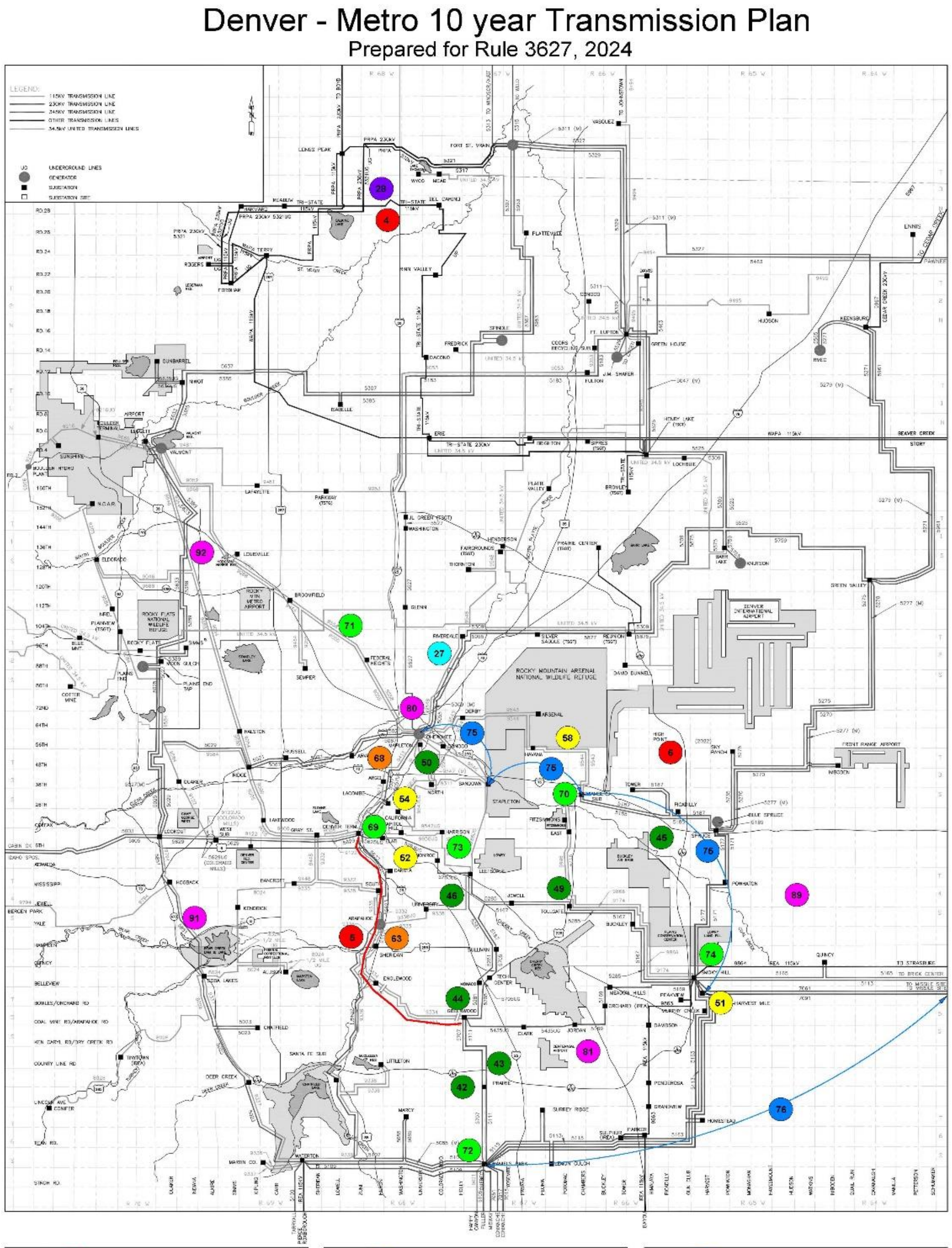
2030

- 75 New Double Circuit 230 kV Line from Harvest Mile-Chambers-Sandown-Cherokee (New, PSCo)
- 76 Phase Shifting Transformer on Missile Site to Daniels Park 345 kV Circuit 7109 (New, PSCo)
- 77 Weld kV1A Replacement and Breaker and Half Project Replacement (WAPA)

Beyond 2030 or ISD TBD

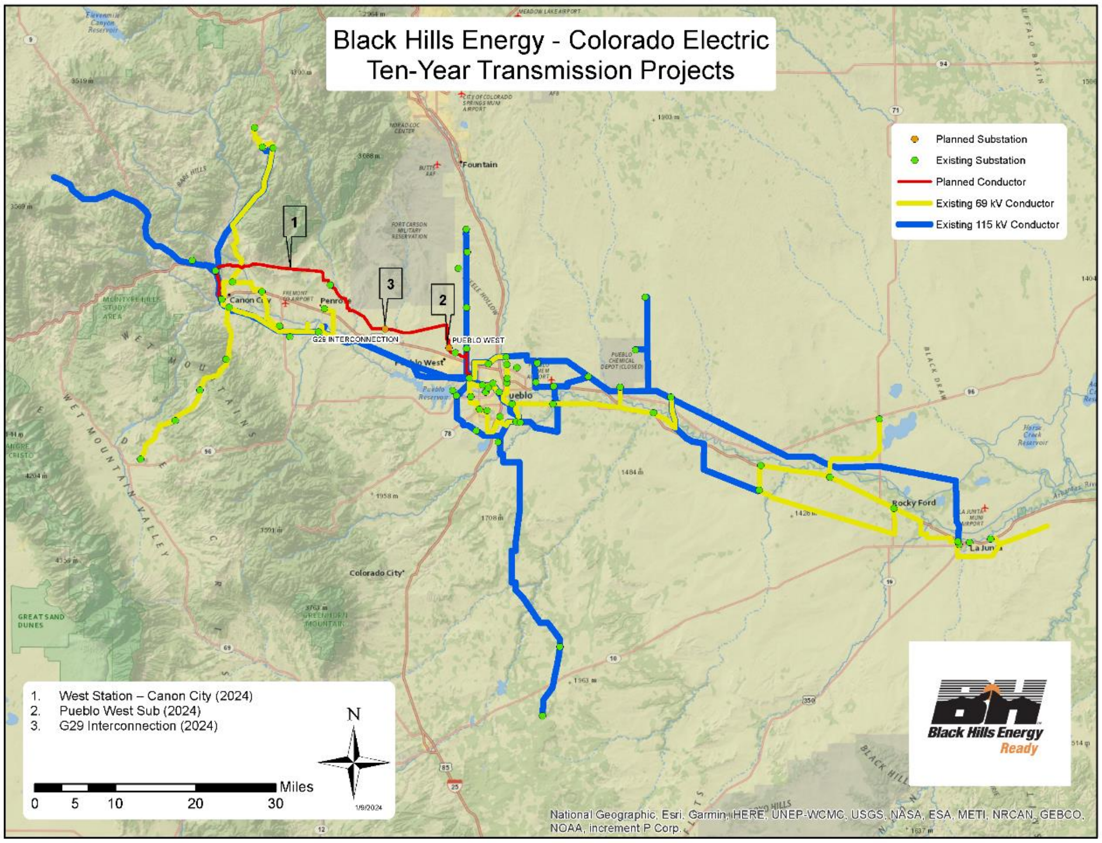
- 78 Blue Mesa Reactor & Transformer (WAPA)
- 79 Carbondale - Crystal 115 kV Transmission (PSCo)
- 80 Denver Metro Area Upgrades (PSCo)
- 81 Dove Valley Distribution Substation (PSCo)
- 82 Gateway South - Craig/Hayden Area Transmission (PSCo)
- 83 Glenwood - Rifle 115kV Transmission (PSCo)
- 84 Lamar DC Tie Replacement (New, PSCo)
- 85 New Castle Distribution Substation (PSCo)
- 86 Northern Colorado Transmission (PSCo)
- 87 Pathway Voltage Control/Support (PSCo)
- 88 Poncha - Front Range 230 kV (PSCo)
- 89 Sandy Creek Distribution Substation (PSCo)
- 90 San Luis Valley - Poncha 230kV Line #2 (Tri-State/PSCo)
- 91 Solterra Distribution Substation (PSCo)
- 92 Superior Distribution Substation (PSCo)
- 93 Weld County Transmission Expansion (PSCo)
- 94 Weld - Rosedale - Box Elder - Ennis 230/115kV (PSCo)
- 95 Wilson Distribution Substation (PSCo)
- 96 Lost Canyon - Main Switch 115kV Line (Tri-State)
- 97 La Junta 115 kV Tie (Tri-State)
- 98 Burlington - Burlington (KCEA) Rebuild (Tri -State)
- 99 Rocky Ford 69-115 kV Conversion Phase I (New, BHCE)
- 100 Rocky Ford 69-115 kV Conversion Phase II (New, BHCE)
- 101 Rocky Ford 69-115 kV Conversion Phase III (New, BHCE)

Figure 2. Denver-Metro map of transmission projects in the 2024 Plan



2022	4	Del Camino - Slater 115kV Line Uprate (Tri-State)
	5	Greenwood - Denver Terminal 230kV Line (New, PSCo)
	6	High Point Distribution Substation (PSCo)
2024	27	Metro Water Recovery Substation (100% customer funded) (New, PSCo)
2025	28	Slater Double Circuit Conversion (Tri-State)
2026	42	Daniels Park to Greenwood Circuit 5707 Uprate (New,PSCo)
	43	Daniels Park to Greenwood Circuit 5111 Uprate (New,PSCo)
	44	Greenwood Substation Bus Tie (New, PSCo)
	45	Kestrel (formerly Project Bronco) Distribution substation (100% customer funded) (New, PSCo)
	46	Leetsdale to University 115 kV Circuit 9338 Uprate (New, PSCo)
	49	Tollgate Substation Load Shift (New, PSCo)
	50	Poder Distribution Substation (PSCo)
2027	51	230 kV Circuit In and Out of Harvest Mile (New, PSCo)
	52	Leetsdale-Elati 230 kV Circuit Underground Tranmission Line Upgrade (New, PSCo)
	54	Barker Distribution Substation (PSCo)
	58	Havana to Chambers Circuits 9543 and 9544 Uprate (New, PSCo)
2028	63	Arapahoe 115 kv Bus Uprate and Second 230/115 kV Transformer (New, PSCo)
	68	Uprate Substations on Circuit 5057 (PSCo)
2029	69	Capitol Hill to Denver Terminal 115 kV Circuit 9007 Uprate (New,PSCo)
	70	Chambers Third 230/115 kV Transformer (New,PSCo)
	71	Cherokee to Broomfield 115 kV Circuits 9055/9558/9464 Uprate (New, PSCo)
	72	Daniels Park Fourth Transformer (New, PSCo)
	73	Leetsdale to Harrison 115 kV Circuit 9955 Uprate (New, PSCo)
	74	Smoky Hill Third Transformer (New, PSCo)
2030	75	New Double Circuit 230 kv Line from Harvest Mile-Chambers-Sandown-Cherokee (New, PSCo)
	76	Phase Shifting Transformer on Missile Site to Daniels Park 345 kV Circuit (New, PSCo)
Beyond 2030 or ISD TBD	80	Denver Metro Area Upgrades (PSCo)
	81	Dove Valley Distribution Substation (PSCo)
	89	Sandy Creek Distribution Substation (PSCo)
	91	Solterra Distribution Substation (PSCo)
	92	Superior Distribution Substation (PSCo)

Figure 3. Pueblo area map of transmission projects in the 2024 Plan



II. Transmission Planning in Colorado

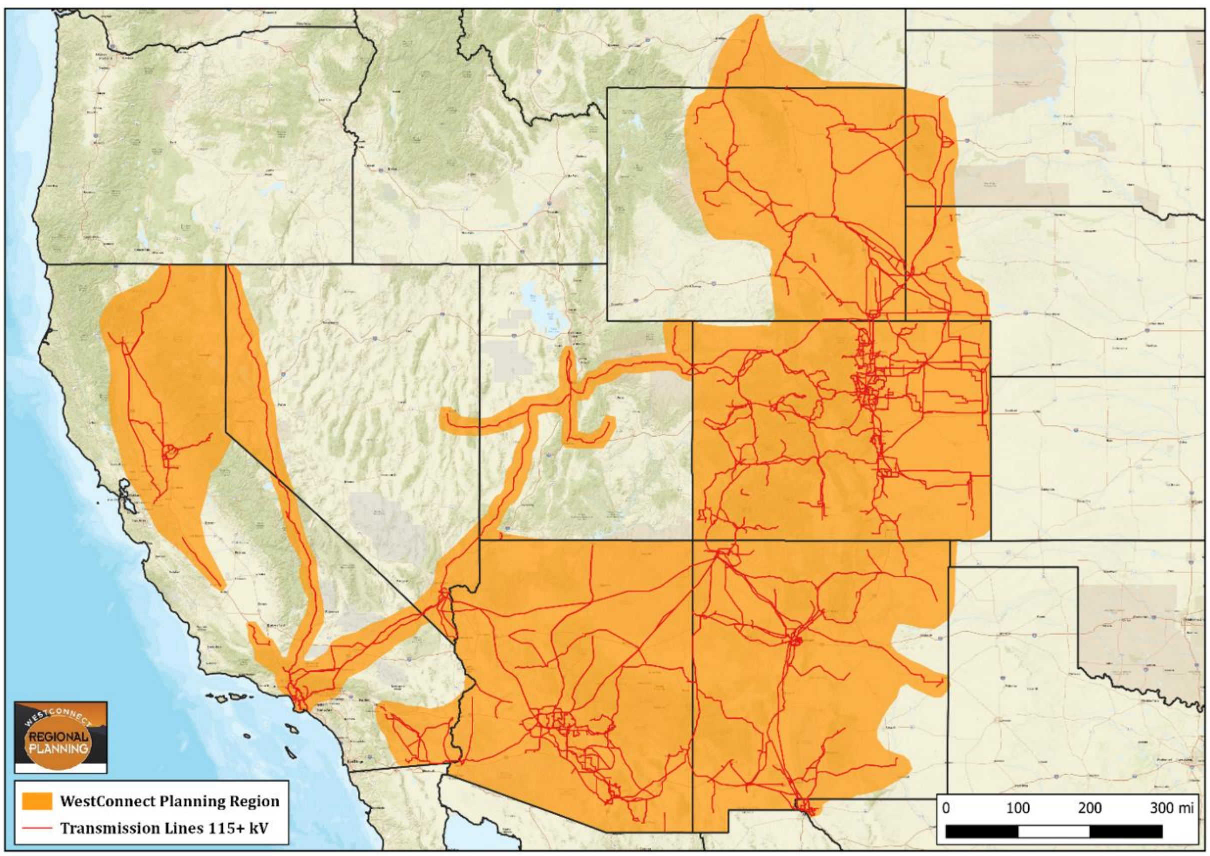
A. Coordinated Planning

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

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

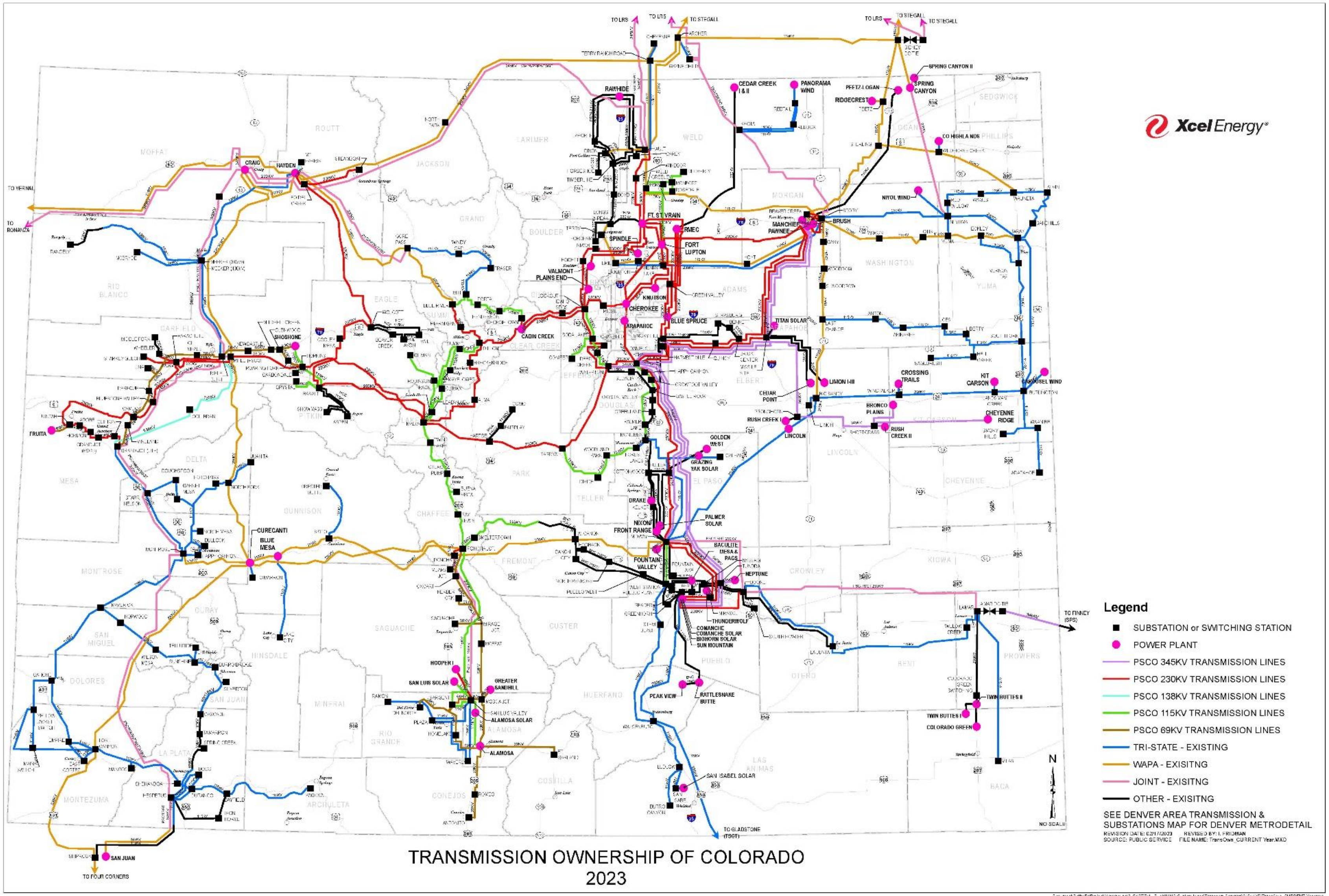
[3] The other two regions are Northern Grid and the California Independent System Operator.

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 (2023)



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; and (3) policy initiatives directly related to transmission infrastructure. Each of these categories is discussed below. In addition to these new policy drivers, many of the drivers described in detail in the 2022 Rule 3627 Report remain relevant to this analysis and should be considered drivers for the 2024 Report as well. These drivers include: (1) Senate Bill ("SB") 19-236 and the Clean Energy Plans (and other emission reduction plans) filed consistent with that law; (2) House Bill ("HB") 21-1261 and the associated rulemakings; (3) HB21-1266; (4) HB18-1270; SB21-272; SB19-077; SB21-1238; SB21-246; SB21-264; SB21-260; SB21-261; HB20-1155; SB20-124; SB18-009; and SB21-072. Description of these policies can be found in the 2022 Rule 3627 Report.

1. Public Policy Developments Related to Decarbonizing the Electricity Sector

A number of legislative developments since the 2022 Rule 3627 Report 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. Clean Energy Plans

Senate Bill 19-236 required retail utilities providing electric service to more than 500,000 customers to submit Clean Energy Plans ("CEPs") to the CPUC meeting certain criteria, including achieving an 80 percent 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 an Electric Resource Plan ("ERP") and CEP in 2021, which is modeled to achieve the required reduction.[4] The legislation also provided that other retail electric utilities may "opt in" and voluntarily submit a CEP upon notification to the

[4] Proceeding No. 21A-0141E.

Commission. Black Hills filed a CEP in 2022.[5] Black Hills' CEP also is modeled to achieve the required reduction. Because Tri-State is not a retail electric utility, it did not submit a CEP with its 2020 ERP[6] but has, nevertheless, committed to an 80 percent carbon dioxide emissions reduction through that ERP (as well as through Tri-State's 2023 ERP, which was filed on December 1, 2023[7]).

In addition to the 2030 carbon dioxide emissions reduction requirement, CEP filings also must seek to reach a goal of 100 percent 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 SB19-236 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, Certificate of Public Convenience and Necessity ("CPCN") filings, and Transmission Cost Adjustment proceedings. SB07-100 Energy Resource Zones will apply to the beneficial resources required for CEP compliance.

Under this framework, CEPs (and the similar emissions reductions in Tri-State's resource plans) 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

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[5] Proceeding No. 22A-0230E.

[6] Proceeding No. 20A-0528E.

[7] Proceeding No. 23A-0585E.

additional energy storage facilities to ensure that the transmission system remains reliable and resilient as high penetrations of renewables are achieved.

b. Inflation Reduction Act, the Infrastructure Investment and Jobs Act, and Other Federal Spending

Since the 2022 Report, new federal funding opportunities have become available through the Infrastructure Investment and Jobs Act of 2021 ("IIJA") and the Inflation Reduction Act of 2022. The Commission opened Proceeding No. 23M-0053ALL to investigate and receive reporting on the Companies' efforts to obtain this funding and the Companies have filed such information into the proceeding. Those filings detail the opportunities each Company is pursuing, some of which could result in funding for transmission projects or for other projects that would impact the bulk transmission system (for example, by increasing the amount of renewable generation).

c. HB22-1381, Colorado Energy Office Geothermal Energy Grant Program and House Bill 23-1252, Geothermal Energy Grant Program

HB 22-1381 created a geothermal energy grant program administered by the Colorado Energy Office ("CEO") to facilitate the development of geothermal heating systems and geothermal electricity generation. House Bill 23-1252 expanded the Geothermal Energy Grant Program created in House Bill 22-1381. To the extent this legislation results in additional installation of geothermal heat pumps, the Companies expect that electric demand could correspondingly increase, driving additional load-serving needs.

d. SB23-016, Measures to Promote Reductions in Greenhouse Gas Emissions

This legislation updates the State of Colorado's statutory greenhouse gas emissions goals to add a 65 percent reduction goal for 2035, an 80 percent reduction goal for 2040, and a 90 percent reduction goal for 2045, as well as amending the state's 2050 goal from a 90 percent reduction goal to 100 percent.

e. SB23-092, Voluntary Emissions Reductions in Agriculture

This legislation provides incentives for the study and use of agrivoltaics, which pairs solar generation with agricultural land uses.

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 drive additional transmission needs 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. HB22-1362, Building Greenhouse Gas Emissions

This legislation updates the state's minimum energy code requirements. Among other things, the bill requires the creation of the building electrification for public buildings grant program, creating the high-efficiency electric heating and appliances grant program, and establishing the clean air building investments fund.

b. HB 22-1218, Resource Efficiency Buildings Electric Vehicles

HB22-1218 creates a requirement for new large commercial building projects and new multifamily residential buildings of a certain size to have electric vehicle ("EV") charging. For commercial buildings, twenty-five percent of the parking spaces used by the occupants of the building must be EV capable (*i.e.* the parking space meets the prerequisites to have charging infrastructure installed), and ten percent must be EV ready (*i.e.* the parking space has charging infrastructure installed). For multifamily residences, 50 percent of the units must have a parking space used by the occupants of the building that is EV capable, and 20 percent must have a space that is EV ready.

c. SB22-051, Policies to Reduce Emissions From Built Environment.

HSB 22-051 aims to decrease carbon dioxide emissions from the built environment in Colorado by providing tax incentives for the purchase and use of certain building systems and materials that produce less carbon dioxide than conventional systems and materials. The bill establishes state income tax credits for the purchase and use of two categories of building systems: (1) residential or commercial heat pump systems and heat pump water heaters installed into real property, and (2) residential "energy storage systems," defined broadly to mean any commercially available, customer-sited systems capable or retaining, storing, and delivering energy by chemical, thermal, mechanical, or other means. For both categories, the tax credit is equal to 10 percent of the purchase price paid. The tax credits may begin as early as January 1, 2023, must begin before January 1, 2025, and will sunset on January 1, 2028.

The legislation also establishes exemptions from state sales, storage, and use taxes for three types of building materials. The first exemption is for "eligible decarbonizing building materials," building materials with a maximum global warming potential, beginning July 1, 2024, and includes asphalt and asphalt mixtures, cement and concrete mixtures, glass, post-tension steel, reinforcing steel, structural steel, wood structural elements, and other similar materials. The second exemption is for air-source and ground-source heat pump systems or heat pump water heater systems used in residential or commercial buildings starting January 1, 2023. The third exemption is for energy storage systems used in a residential dwelling starting January 1, 2023.

d. HB23-1281, Advance the Use of Clean Hydrogen

This legislation defines clean hydrogen as hydrogen that is derived from a clean energy source that uses hydrogen and emits less than 1.5 kilograms of carbon dioxide per kilogram of hydrogen when produced. The bill creates a refundable income tax credit for using clean hydrogen in addition to a state approval system process through the CPUC for clean hydrogen projects.

e. SB23-016, Greenhouse Gas Emission Reduction Measures

Among other programs designed to reduce greenhouse-gas emissions, this legislation creates tax incentives for the purchase of electric-powered lawn equipment.

3. Public Policy Developments Related to Transmission Infrastructure

a. HB22-1104

This bill encourages the development of powerline trails—multimodal recreational trails located in existing or future transmission corridors. The bill authorizes transmission providers to contract with public and private entities to construct and maintain powerline trails. The bill also imposes various requirements on different entities. Transmission providers must discuss the potential for powerline trails when notifying local governments about plans to site or expand transmission lines, and they must also develop, maintain, and distribute information to encourage, facilitate, and streamline the construction and maintenance of such trails. Public entities must consult with the Division of Parks and Wildlife to minimize adverse impacts to species and habitats. Finally, the CPUC must amend its rules to include a requirement that utilities consider and address plans for new powerline trails in coordination with local governments in each update to a 10-year transmission plan, and to demonstrate compliance with the informational requirements of the bill in their 10-year plan filings. The legislation also requires the Commission to amend its rules requiring the filing of 10-year transmission plans by utilities to require utilities to consider and address powerline trails in coordination with applicable local governments in each two-year update to a 10-year transmission plan.

C. Emerging Issues[8]

The Companies have identified on the following emerging issues for discussion in the 2024 10-Year Transmission Plan.

1. Organized Markets

Colorado Senate Bill 21-072 requires, in part (C.R.S. § 40-5-108), that Colorado transmission utilities[9] join an OWM on or before Jan. 1, 2030. 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, or 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).

The Commission opened Proceeding No. 22R-0249E to consider the adoption of rules related to Senate Bill 21-072 that would govern the Companies' participation in OWMs. Numerous comments have been filed in response to the ongoing rulemaking and the Commission also has taken comments in rulemaking hearings, most recently on September 12, 2023.

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 additional steps

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[8] 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.

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

are being taken by the Commission and Colorado electric utilities toward participation in an organized market and compliance with SB21-072.

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. Extreme summer temperatures are driving increased electricity demand at the same time they create increased risk of wildfires that threaten the electric grid. However, 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 efforts.

3. Grid Resilience and Reliability; Microgrids

HB22-1249 requires the CEO to produce a Grid Resilience and Reliability Roadmap (Roadmap) by March 1, 2025. The bill also requires the CEO to publish a draft of the Roadmap by July 1, 2024; appropriates $22,470 for developing the Roadmap; and mandates a 30-day public comment period. The Roadmap will identify Colorado's microgrid goals, financial and technical needs with respect to microgrid development and deployment and will develop legislative and administrative recommendations. Accordingly, HB22-1249 requires the Roadmap to consider critical facilities and infrastructure, microgrid technologies, utility wildfire mitigation plans, and Colorado's greenhouse gas emission reductions and transition to clean energy. The bill also requires the CEO to seek input from: microgrid developers; the CPUC and Commission staff; the Colorado Office of the Utility Consumer Advocate ("UCA"); utilities; commercial and industrial utility customers; representatives of disproportionately impacted communities; and representatives of communities at the highest risk of power outages, among others.

HB22-1013 creates the Microgrid for Community Resilience Grant Program within the Department of Local Affairs ("DOLA"). Under the program, cooperative electric associations and municipally owned utilities can apply for a grant to purchase microgrid resources in eligible rural communities (located within their service territories). HB22-1013 defines an eligible rural community as one “at significant risk of experiencing severe weather or natural disaster events; and in which one or more community anchor institutions [schools, libraries, hospitals, etc.] are located.” The $3.5 million grant program will be administered by DOLA’s Division of Local Government in collaboration with the Colorado Resiliency Office and the CEO. HB22-1013 requires the Division of Local Government to: (1) prioritize microgrids with a higher reliance on non-fossil-fuel-based generation when awarding grants, and (2) consider the opportunity for a utility to promote energy efficiency and demand-side management programs.

D. Alternative Technologies

The Companies considered alternative technologies, such as non-wires alternatives (“NWAs”) and advanced transmission technologies (“ATTs”), as opposed to conventional transmission projects in the development of the 10-Year Transmission Plan. Generally speaking, ATTs are technology that increase the capacity, efficiency, or reliability of existing and new transmission facilities, and NWAs are system alternatives that do not rely on the construction of new transmission or distribution lines to solve an identified need. 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 ("AAR") 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. Transmission providers are required to implement AAR in compliance with FERC Order No. 881 by July 12, 2025. While Order No. 881 could have implications for the Companies' use of DLR, FERC declined to mandate DLR implementation at this time, but will continue to explore the topic 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 include 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 include 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 improve 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 renewable energy curtailments. Energy storage is typically installed in conjunction with wind and/or solar generation facilities. In 2023, CCPG's Energy Storage and Non-Wires Alternatives Working Group ("ESWG") published "A Guide to Evaluating Energy Storage Alternatives" to serve as a reference guide for transmission planners to use when considering the feasibility, reliability, and economics of energy storage or non-wires alternatives. The Evaluation Guide is available for download at: https://doc.westconnect.com/Documents.aspx?NID=21026.

6. 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 High Temperature, Low Sag ("HTLS") conductors include composite core conductors, which are capable of higher operating temperatures (up to 200 degrees Celsius) with reduced sag. The specific type of conductor selected for a transmission project is not necessarily within the scope of a transmission planning evaluation. This is because transmission planning studies identify the minimum rating of a transmission line necessary to meet the need but do not typically evaluate which materials are the most capable or cost-effective solution to provide that rating (unless, for example, the suitability of rebuilding or reconductoring an existing transmission line were an alternative under evaluation as a planning solution). In this respect, all conductor types are generally considered as potential solutions within a transmission planning analysis; however, specific conductors to meet the ampacity needs are identified and selected as part of the later detailed engineering of transmission projects. The Companies' transmission line engineers are responsible for evaluating and developing the most appropriate facility design that meets the electrical need identified in the planning process, and these types of alternatives are presented and addressed through CPCNs.

III. Company Plan Narratives

A. Black Hills 10-Year Plan Overview

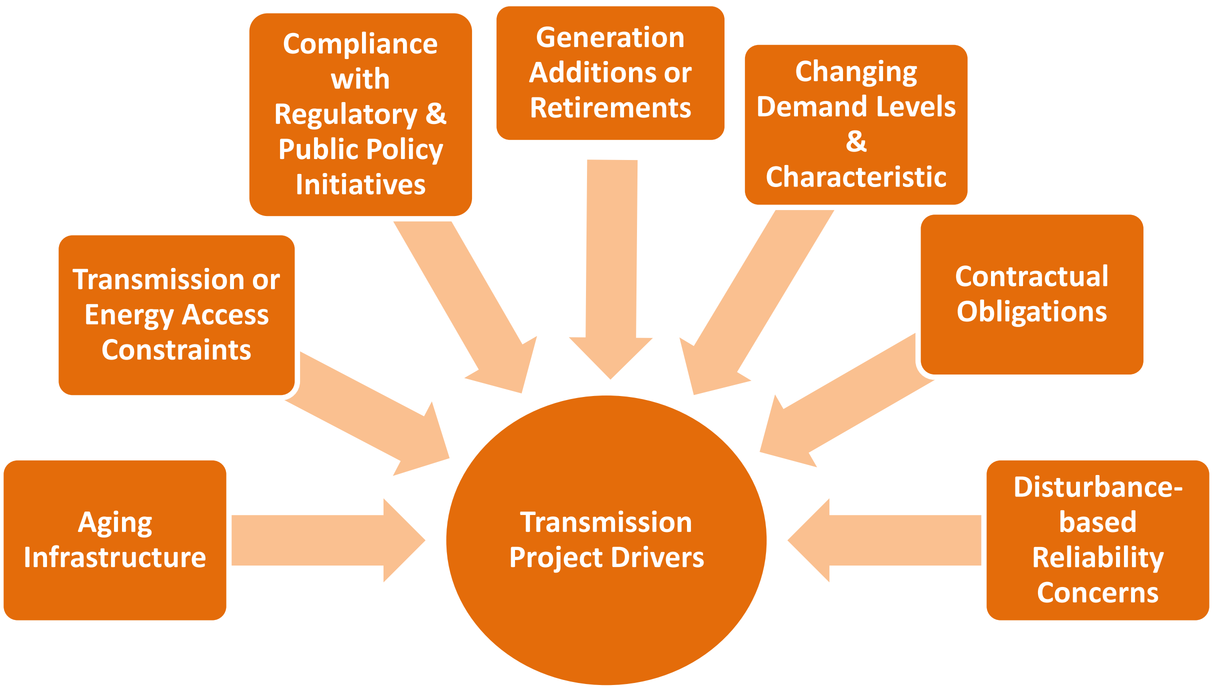
1. Black Hills Service Territory

Black Hills Colorado Electric, LLC, a division of Black Hills Corporation, serves over 100,000 customers in south-central Colorado. The counties served are parts of Crowley, Custer, El Paso, Fremont, Otero, Pueblo, and Teller. Twenty-one communities are served, and of these, the largest communities are Pueblo, Cañon City, and Rocky Ford.

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

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

Figure 6. Needs that Drive Transmission Development



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

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

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

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

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

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

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

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

2. Black Hills Projects

a. Renewable Advantage (200 MW)

On November 22, 2019, Black Hills filed an Application in Proceeding No. 19A-0660E requesting to amend its 2016 ERP. The Company sought approval to add up to 200 MW of eligible renewable energy and/or storage resources through a competitive solicitation. On December 13, 2019, the Company issued the Request for Proposals ("RFP") and requested bids by February 15, 2020. The Company received 54 individual bids from 25 project developers in response to its RFP, including standalone wind, solar (PV), and storage, in addition to bids that offered battery storage technology in combination with solar (PV) generation facilities.

TC Colorado Solar, LLC ("TC Colorado") was ultimately selected as the winning bidder and Black Hills and TC Colorado were able to arrive at a Purchase Power Agreement ("PPA"). However, on January 31, 2022, TC Colorado provided the Company with a Notice of Termination of the PPA. On February 3, 2022, the Company responded to the notice. Among other things, the response requested use of the dispute resolution process in the PPA to resolve issues with the project.

The Parties worked together to try to resolve issues; however, it became apparent that TC Colorado could not provide reasonable assurances of its ability to deliver the project at a price that provides savings to customers – a central premise to the Renewable Advantage proceeding. Black Hills notified TC Colorado of this conclusion and that it would not be moving forward with discussions surrounding a potential Amended PPA. The existing PPA is therefore terminated effective as of the termination notice TC Colorado provided in January.

With the termination of the Turkey Creek project, Black Hills has thus delayed the West Station-Hogback 115kV Transmission Project. Resources already procured for this project will be utilized for other projects the Company has planned.

On May 27, 2022, Black Hills filed its 2022 ERP, including a Clean Energy Plan (CEP) to reduce the Company's carbon dioxide (CO_2) emissions by a target of 80 percent by 2030 as compared to 2005 levels. In Decision No. C23-0193 in Proceeding No. 22A-0230E, the Commission approved a settlement agreement, with modifications, which authorized Black Hills to increase its Planning Reserve Margin to 20 percent in 2023, and the Company acquiring approximately 400 MW of (primarily) solar, wind, and storage resources by 2030. Phase II of the ERP/CEP proceeding has commenced, with Black Hills issuing an RFP on July 31, 2023. On October 20, 2023, the Company received over 140 bids from bidders. On December 19, 2023, bidder notifications (indicating which bids are advancing to computer modeling) were issued. The Company will issue its 120-day report indicating its preferred portfolio and other portfolios by April 17, 2024.

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 2024 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 2024 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 2022 10-Year Plan, Black Hills has completed five projects: Hogback 115/69 kV substation, West Station – Greenhorn 115 kV line rebuild, South Fowler Substation, Boone – S Fowler 69 to 115 kV conversions, and North Penrose Distribution substation. Black Hills identified four planned projects within the upcoming 10-year planning horizon that represent $40.6 million in capital expenditures between 2023 and 2025. 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. These projects are also needed to support a 200 MW generator interconnection in the area.

Table 2. Cañon City area projects included in the Black Hills 2024 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
West Station – Hogback Transmission Line[10] AKA West Station- Canon City	2/2024	$25.8	Not required. Decision No. C23-0810
BHCT G29 Interconnection Substation	12/2024	$6.2	TBD
Canon West 230/114 kV XFMR Replacement	12/2024	$4	TBD

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 replacement of the Canon West transformer and the BHCT G29 interconnection substation will support the 200 MW interconnection bringing increased load serving capability to the area.

Pueblo area

One project, shown in Table 3, addresses 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.

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

Table 3. Pueblo area projects included in the Black Hills 2024 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
115kV Pueblo West Distribution Substation	2/2024	$5.4	Not required Decision No. C20-0477

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.

Rocky Ford area

Three conceptual 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 2024 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Rocky Ford Phase i	TBD	TBD	TBD
Rocky Ford Phase II	TBD	TBD	TBD
Rocky Ford Phase III	TBD	TBD	TBD

The Rocky Ford 69/115 kV conversion is a conceptual project that will replace ageing infrastructure, support the retirement of the Rocky Ford diesels and provide increased capacity for bringing renewable resources into the area. Phase 1 will upgrade the 10.8 mile 69 kV line from Rocky Ford – La Junta to 115 kV, upgrade the Rocky Ford substation to 115 kV and expand the La Junta substation. Phase 2 will rebuild 3.4 miles of 69 kV line from Fowler to S. Fowler, 8.8 miles of 69 kV line from Fowler to Manzanola and 8.9 miles of 69 kV line from Manzanola to Rocky Ford to 115 kV. The distribution transformers at Ordway, Fowler and Manzanola will all be increased from 10 MVA to 14 MVA. Phase 3 will upgrade 21.3 miles of 69 kV line from Rocky Ford to S Fowler to 115 kV.

Information concerning the specific Colorado projects included in the Black Hills 2024 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.

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 2024 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 2024 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 2024 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 improvements, congestion relief, or the accommodation of new generation. It should be noted that the 2024 Plan includes some projects listed in the 2022 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 (for example, through Tri-State's 2023 Electric Resource Plan) 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 2024 10-Year Plan

Project Name	**Estimated In-Service Date**	**Cost (millions)**	**CPCN**
Big Sandy-Badger Creek 230 kV Line	2028	$65.6	Issued
Burlington-Lamar 230 kV Line	2025	$89.0	Issued
Cross Point 230/69kV Delivery Point	2025	$12.0	NR
Fox Run Substation Expansion	2024	$15.1	NR
Rolling Meadows 115 kV Delivery Point	2026	$7.9	NR
Lost Canyon-Main Switch 115 kV Line**	TBD	TBD	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, Colorado.

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.

Cross Point 230/69kV Delivery Point

This project will build a new 230/69kV substation that will interconnect to and sectionalize Tri-State's existing Lincoln-Midway 230kV line near Yoder, CO. This substation will tie into existing Tri-State Member owned 69kV sub-transmission that serves high growth communities to the east of Colorado Springs, CO. The existing Delivery Points that serve this 69kV system are reaching their capacities under contingency and would need significant upgrades to increase load serving. Additionally, it was becoming difficult to maintain adequate voltages at the ends of the 69kV system. Crosspoint will provide an additional Delivery Point to the area, which will substantially increase load serving and reliability. Note that this project has replaced Tri-State's previously planned Falcon-Paddock-Calhan 115kV project as it provides better performance at a reduced cost and without the need to construct additional transmission lines.

Fox Run Substation Expansion

This project will re-build the existing Monument 115/12.47kV substation as a breaker-and-a half 115kV bus configuration in a new adjacent yard known as "Fox Run." Today Monument's 115kV bus is in a "star" configuration, and as such breaker failures or bus faults can clear the entire bus, resulting in substantial loss of load in the area. The new breaker configuration will eliminate this allowing for minimal facilities to be tripped during such fault conditions. Additionally, this project will add two new 115/12.47kV transformers that will improve load serving and reliability for the loads served directly out of Monument substation.

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.

Rolling Meadows 115 kV Delivery Point

This project consists of a newly constructed 115/12.47kV substation interconnecting to Tri-State's existing Geesen-Lorson Ranch 115kV line near Colorado Springs, CO. This substation is needed to serve a new housing development and associated infrastructure.

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	$65.6	Issued
Big Sandy-Burlington 230 kV Line Uprate	2028	$7.0	NR
Burlington-Burlington (KCEA) Rebuild**	TBD	TBD	NR
Burlington-Lamar 230 kV Line	2025	$89.0	Issued
Cross Point 230/69kV Delivery Point	2025	$12.0	NR
Fox Run Substation Expansion	2024	$15.1	NR
La Junta 115 kV Tie**	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	2025	$7.2	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.

Burlington-Lamar 230 kV Line

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

Cross Point 230/69kV Delivery Point

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

Fox Run Substation Expansion

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

La Junta 115 kV Tie

This project constructs a new transmission line between Tri-State's La Junta substation and Black Hills' La Junta substation. Without a tie connecting these two substations, certain contingencies and outages in the area produce line overloads resulting in dropped load.

Lost Canyon Main Switch 115 kV 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	$65.6	Issued
Big Sandy-Burlington 230 kV Line Uprate	2028	$7.0	NR
Boone-Huckleberry 230 kV Line	2026	$37.3	Issued
Burlington-Lamar 230 kV	2025	$89.0	Issued
Cahone Line Bay Addition	2024	$0.72	NR
Garnet Mesa Solar Interconnect	2024	$2.4	NR
Main Switch Bay Addition	2025	$2.8	NR
Milk Creek Switching Station	2025	$13.3	NR
Valent 230 kV Switching Station	2024	$6.3	NR

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.

Cahone Line Bay Addition

This under construction project is adding a 115 kV line bay at the existing Cahone Substation to accommodate a solar interconnection (Dolores Canyon Solar).

Garnet Mesa Solar Interconnect

This project is adding a 115 kV line bay at the existing Garnet Mesa Substation to accommodate a solar interconnection.

Main Switch Bay Addition

This project is adding a 115 kV line bay at the existing Main Switch Substation to accommodate a solar interconnection.

Milk Creek Switching Station

This project is constructing a 345 kV Switching Station along Craig-Meeker 345 kV. This will accommodate a solar interconnection (Axial Basin).

Valent 230 kV Switching Station

This project will tap the existing Walsenburg-Gladstone 230 kV line to serve Spanish Peaks Solar.

3. Tri-State Alternative Technologies

There are no new transmission projects in Tri-State's 2024 Transmission Plan and, as such, no alternative technologies were considered in the context of new transmission projects.

Information concerning the specific Colorado projects included in the Tri-State 2024 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 1.6 million electric customers in the State of Colorado. Its electric system is summer peaking, with a 2023 peak customer demand of 7,364 MW. The entire Public Service transmission network is located within the State of Colorado and consists of approximately 5,000 circuit 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 ("SPS"), via a jointly owned tie line with a 210 MW High Voltage Direct Current ("HVDC") back-to-back converter station. Most of the Public Service retail service customers are located in the Denver-Boulder metro area. However, the Public Service retail service territory also includes portions of the I-70 corridor to Grand Junction, the San Luis Valley region, and the cities and towns of Greeley, Sterling, and Brush.

One of Public Service's strategic priorities is to be a leader in transitioning its resource mix to clean energy sources. Xcel Energy, Public Service's parent company, aspires to deliver 100 percent carbon-free electricity to customers by 2050, with an interim goal of reducing carbon emissions from electric generation 80 percent below 2005 levels by 2030. In Colorado, Public Service's implementation of its 2030 clean energy goals comes through the Clean Energy Plan process created in SB19-236. Public Service filed its Clean Energy Plan with the Commission in 2021 in Proceeding No. 21A-0141E. The resulting resource and grid transformation needs are and will remain a significant factor in Public Service's transmission planning efforts for many years to come.

In this Ten-Year Transmission Plan, Public Service only presents one new Planned Project, which is a new switching station related to the Colorado's Power Pathway Project identified in the 2022 Ten-Year Plan. However, Public Service presents a significant number of new Conceptual Projects that will be needed to maintain system reliability, accommodate new clean energy generating resources, or support new customer demand. Pending the completion of the transmission planning process, including stakeholder engagement, these projects are still in the preliminary stages of analysis and cannot yet be identified as Planned Projects.

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, with an emphasis on long-term planning.

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, accommodates current and future load growth, enables integration of new resources, while fulfilling the following principles:

- Maintain reliable electric service by ensuring 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 short and long-term customer load growth, accommodation of new generation resources, retirement of existing generation 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 it some level of uncertainty. As transmission planners consider different planning horizons, such as two-, five- and ten-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.

Public Service's approach to transmission planning prioritizes the identification of cost-effective projects that prioritize the resiliency and reliability of the transmission network. Transmission projects must accomplish the goal of relieving potential overloads as well as providing operational flexibility to account for unexpected outages and unique operational circumstances. Further, Public Service seeks to enhance value by identifying and pursuing projects with multi-level benefits. If a transmission project can alleviate multiple violations at various locations, then that project is deemed to provide multiple benefits and is considered a preferred solution. Public Service also considers the use of ATTs and NWAs as potential solutions in whole or part.

Public Service's stakeholder-driven transmission planning process 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 Public Service's participation in the Colorado Coordinated Planning Group and its individual subcommittees, task forces and working groups as well as Public Service's yearly (in Q1 and Q4) stakeholder engagements in accordance with FERC Order 890 and CPUC Rule 3627.

The consideration of a broad set of project alternatives, including relevant ATTs and NWAs, is an inherent part of Public Service's planning process. Public Service follows its established process for evaluating project alternatives per the Xcel Energy Operating Companies Joint Open Access Transmission Tariff ("OATT"). Per the OATT's 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."

2. Advanced Transmission Technologies

New transmission technologies will play an essential role in maximizing the value of the transmission system, lines, and substations, with ATTs considered within Public Service's planning processes. While the applicability of an ATT solution is dependent on the specific transmission system needs and solutions, Public Service generally evaluates the ATTs described in Section II.D. of this 10-Year Plan in its transmission planning processes. Public Service presents information to the Commission and stakeholders about the suitability or applicability of ATTs and engineering alternatives in applications for CPCNs or annual Rule 3206 Reports as relevant.

Consistent with the requirements of Commission Rules 3627 and 3206, as well as Decision No. R21-0073, Public Service has evaluated the suitability of relevant ATTs for all new planned transmission projects identified in the Ten-Year Plan. Details about the analysis of ATTs are discussed in project descriptions below. Relevant ATTs will be fully evaluated for all Conceptual Projects before those projects become Planned Projects. Public Service does not have a Planned Project for which an ATT or NWA has been selected in this Ten-Year Plan; however, the expected applicability of ATTs has been identified for several Conceptual Projects that are still under evaluation as described below.

3. Public Service Projects

Public Service's Planned and Conceptual transmission projects can generally be placed in two categories. The first category consists of projects that are needed primarily for load growth or reliability purposes. These include new transmission facilities as well as capacity upgrades to existing transmission facilities. 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. SB07-100 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 Energy Resource Zones ("ERZs") that have high potential to host future renewable generation facilities. The SB07-100 projects that have been completed to-date, or are currently under construction, will comprise the backbone transmission system that will be gainfully leveraged to interconnect and deliver to load centers the resources acquired through current and future resource plans. As Public Service's transmission analysis provided in support of the 120-Day Report in the 2021 ERP & CEP demonstrates, Public Service expects that the acceleration of the transition of Public Service's generation system to renewable energy resources that are predominantly located in remote areas of the state will have further effects on the transmission system in and around the Denver metro area. Further, as new renewable energy resources come online, changes in power flow across the system may require additional voltage support equipment.

Table 8 below lists Public Service's planned and conceptual transmission projects identified within the 10-year planning horizon of this Report. This table includes the WECC Base Case selected and applicable summer peak load or winter peak load for the Public Service Balancing Authority Area ("BAA") for the purposes of transmission planning studies, with further planning study detail provided in Appendix F. For many of the conceptual projects listed in this table, Public Service has not completed the transmission planning process and key assumptions and inputs are not yet identified.

Public Service does not provide a total estimated capital cost for transmission expansion necessary to meet estimated 2034 loads given that capital cost estimates are not available for conceptual projects and conceptual projects may change or not be pursued based on evolving system needs. Instead, this table provides cost estimates for individual projects where that estimate has been developed with a reasonable level of assurance consistent with Public Service's criteria for reporting project cost estimates within Annual Rule 3206 Reports, as Public Service first implemented in its 2023 Rule 3206 Report in Proceeding No. 23M-0005E. For completed projects, the costs listed are the final cost that Public Service incurred in constructing the project. Most conceptual projects, as well as some planned projects, are listed with cost estimates and in-service dates of "TBD," as Public Service has not yet completed sufficient development activities to present a reliable project cost estimate or schedule. As the need for these projects becomes clearer through either system growth or regulatory proceedings, more complete studies will be conducted and the costs, in-service dates, and other relevant assumptions and estimates developed. Public Service provides estimated in-service dates for some Conceptual projects listed in this table based on the analysis conducted in Phase II of the 2021 ERP & CEP and presented in the 120-Day Report in that proceeding but notes that these in-service dates may be subject to change through the completion of the transmission planning and CPCN application processes for those projects. To the extent Public Service were to move forward with any of the Conceptual projects presented in this Ten-Year Transmission Plan, cost estimates and project schedules will be updated as part of a future CPCN filing or filing requesting a Commission determination that no CPCN is needed, such as the annual Rule 3206 Report.

Table 8. Public Service 10-Year Plan Projects

Project Name	ISD	Capital Cost ($ millions)[11]	Year Study Completed	WECC Base Case Studied	BAA Winter Peak Demand (MW)[12]	BAA Summer Peak Demand (MW)	CPCN[13]
Transmission Projects Completed 2022-2024							
Avery Substation	2022	$12.3	2015	2023HS2	N/A	10,511	G
CEPP Voltage/Reactive Support	2022	$67.3	2019	2028HS1	N/A	8,873	G
Comanche Substation – Sun Mountain Generation Interconnect (CEPP bid 077)	2022	$1.7	2021	2023HS2	N/A	10,511	NR
Greenwood – Denver Terminal 230kV line	2022	$102.7	2020	2025HS2	N/A	8,738	G
High Point Distribution Substation	2022	$18.9	N/A	N/A	N/A	N/A	G
Mirasol (formerly Badger Hills) Switching Station (CEPP Bid X647)	2022	$22.8	2021	2023HS2	N/A	10,511	G
Tundra Switching Station (CEPP Bid X645)	2022	$21.9	2020	2023HS2	N/A	10,511	G
Bluestone Valley Substation Phase 2	2023	$18.6	2020	2024HS	N/A	8,455	NR
New Planned Transmission Projects							
Sandstone Switching Station	2027	TBD, part of Pathway Project budget	2021[14]	2030HS1	N/A	10,273	R
Previously Identified Planned Projects							
Generator Interconnection Facilities							
Midway Substation – Generation Interconnect[15]	2025	$1.7	2020	2017HS1	N/A	N/A	G
Stagecoach Switching Station	2025	TBD	2018	2022HS1	N/A	N/A	U
Transmission Network Upgrades							
Ault-Cloverly 230/115 kV Transmission	2024	$123.5	2017	2026HS2	N/A	9,103	G
Avon-Gilman 115 kV Transmission	2027	TBD	2014	N/A	N/A	N/A	NR

[11] Capital costs identified in this table include transmission-related costs only and do not include the cost of any distribution-related assets for projects that include both transmission and distribution assets.

[12] Peak demands are not generally applicable to all project analyses. Peak demand values are calculated at the time of the study and may not reflect current peak demand calculations.

[13] CPCN Key: R – Required, NR – Not Required, G – Granted, U - Uncertain

[14] The Sandstone Switching Station is planned based on the transmission planning study completed for the Colorado's Power Pathway project, as it is an engineering scope change that does not alter the electrical performance of the Pathway Project.

[15] While the PPA selected in the Colorado Energy Plan associated with this project failed, the developer still has an active LGIA with Public Service that requires the construction of these interconnection facilities.

Colorado's Power Pathway (With May Valley – Longhorn Extension)	2027	$1,685 (MVLE $TBD)	2021	2030HS1	N/A	10,273	G
New Conceptual Projects							
Transmission Network Upgrades							
Leetsdale – Elati 230 kV Circuit 5283 Underground Transmission Line Upgrade	2027	TBD	Study ongoing	N/A	N/A	N/A	R
2021 ERP & CEP Network Upgrades							
Uprate Substations on Circuit 3006 Poncha West and San Luis Valley	2025	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Uprate Substations on Circuit 9811 Poncha Junction and San Luis Valley	2025	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Daniels Park to Greenwood Circuit 5707 Uprate	2026	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Daniels Park to Greenwood Circuit 5111 Uprate	2026	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Greenwood Substation Bus Tie Uprate	2026	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Leetsdale to University 115 kV Circuit 9338 Uprate	2026	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Midway Substation 230 kV Bus Uprate	2026	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
San Luis Valley 115 kV Circuit 9431 Uprate	2026	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Tollgate Substation Load Shift	2026	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
230 kV Circuit 5165 In and Out of Harvest Mile	2027	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Havana to Chambers Circuits 9543 and 9544 Uprate	2027	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Midway Substation 230/115 kV Transformer Replacement	2027	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Alamosa to Mosca to San Luis Valley 69 kV Circuits 6935/6936 Uprate	2028	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Arapahoe 115 kV Bus Uprate and Second 230/115 kV Transformer	2028	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Malta to Poncha Junction Circuit 9255 Uprate	2028	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
New 115 kV Line San Luis Valley to Alamosa Terminal	2028	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Uprate Substations on Circuit 5057	2028	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Capitol Hill to Denver Terminal 115 kV Circuit 9007 Uprate	2029	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Chambers Third 230/115 kV Transformer	2029	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Cherokee to Broomfield 115 kV Circuits 9055/9558/9464 Uprate	2029	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Daniels Park Fourth Transformer	2029	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Leetsdale to Harrison 115 kV Circuit 9955 Uprate	2029	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Smoky Hill Third Transformer	2029	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U

New Double Circuit 230 kV Line from Harvest Mile – Chambers – Sandown – Cherokee	2030	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Phase Shifting Transformer on Missile Site to Daniels Park 345 kV Circuit 7109	2030	TBD	Study ongoing	Study ongoing	Study ongoing	Study ongoing	U
Interregional Transmission Capacity Expansion							
Lamar DC Tie Replacement	TBD	TBD	Study ongoing	N/A	N/A	N/A	U
Previously Listed Conceptual Projects							
Weld-Rosedale-Box Elder – Ennis 230/115kV Transmission	TBD	TBD	Study ongoing	2027HS1	N/A	9,165	R
Weld County Transmission Expansion	TBD	TBD	N/A	N/A	N/A	N/A	R
Glenwood-Rifle 115 kV Transmission	TBD	TBD	N/A	N/A	N/A	N/A	U
San Luis Valley – Poncha 230 kV Transmission	TBD	TBD	2016	2020HS2	N/A	8,387	R
Poncha – Front Range 230 kV Transmission	TBD	TBD	2017	2026HS	N/A	9,103	R
Carbondale – Crystal 115 kV Transmission	TBD	TBD	Study ongoing	2026HW	8,351	N/A	R
Pathway Voltage Control / Reactive Support	TBD	TBD	Pending	2032HS	N/A	11,405	R
Interregional Transmission Capacity Expansion							
Northern Colorado Transmission	TBD	TBD	Study ongoing	N/A	N/A	N/A	R
Gateway South – Craig / Hayden Area Transmission	TBD	TBD	Study ongoing	N/A	N/A	N/A	R
Distribution Driven Projects							
Metro Water Recovery Substation (100% customer funded)	2024	$16	N/A	N/A	N/A	N/A	NR
Kestrel Substation (100% customer funded)	2026	$28.1	N/A	N/A	N/A	N/A	U
Poder Distribution Substation	2026	$5.9	N/A	N/A	N/A	N/A	NR
Barker Distribution Substation	2027	TBD	N/A	N/A	N/A	N/A	NR
Wilson Distribution Substation	TBD	TBD	N/A	N/A	N/A	N/A	NR
Dove Valley Distribution Substation	TBD	TBD	N/A	N/A	N/A	N/A	NR
New Castle Distribution Substation	TBD	TBD	N/A	N/A	N/A	N/A	NR
Solterra Distribution Substation	TBD	TBD	N/A	N/A	N/A	N/A	U
Superior Distribution Substation	TBD	TBD	N/A	N/A	N/A	N/A	U
Sandy Creek Distribution Substation	TBD	TBD	N/A	N/A	N/A	N/A	U
Lowry Distribution Substation	TBD	TBD	N/A	N/A	N/A	N/A	U
North Sheridan Distribution Substation	TBD	TBD	N/A	N/A	N/A	N/A	U
Berkley Distribution Substation	TBD	TBD	N/A	N/A	N/A	N/A	U
Gray Street Distribution Substation	TBD	TBD	N/A	N/A	N/A	N/A	U
Blue Spruce Distribution Substation	TBD	TBD	N/A	N/A	N/A	N/A	U
Wellington Distribution Substation	TBD	TBD	N/A	N/A	N/A	N/A	U

Public Service's transmission plan does not currently include multi-state regional transmission projects. However, Public Service has conceptually identified three project opportunities in this plan for interconnection to out-of-state planned transmission that could enhance Colorado's import/export capability.

Following is a brief, narrative description of each Public Service Planned or Conceptual Transmission Project. Information for the projects shown in Table 8, as well as maps of the Public Service projects, can be found in Appendix F. Additional information and supporting documentation can also 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

a. Projects Completed Since 2022

This section describes the Public Service projects that have been placed in-service since the 2022 Rule 3627 10-Year Transmission Plan.

Avery Substation[16]

The project consisted of constructing a new substation in Weld County, approximately three miles south of the Platte River Power Authority Ault – Timberline 230 kV line. The new substation tapped the Ault – Timberline 230 kV transmission line using 230 kV double-circuit transmission and an in-and-out termination configuration. The substation includes a three-breaker ring design and a single 230/13.8 kV, 28 MVA transformer but is 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. The project was placed in service in 2022 at a final cost of $12.9 million.

[16] This project also has been referred to in previous Public Service reporting as DCP Timnath.

Bluestone Valley Substation Expansion (Phase 2)

The Bluestone Valley Phase 2 project consisted of expanding the existing Bluestone Valley substation to include 230 kV facilities, including a 230/69 kV transformer and an interconnection to the Rifle-Cameo 230 kV line. The project does not require a CPCN per CPUC Decision No. C21-0256-I. The project was placed in service in December 2023 at a final cost of $18.5 million.

CEPP Generation Interconnection Facilities

Public Service completed the construction of two new switching stations, the Mirasol 230 kV Switching Station and the Tundra 345 kV Switching Station, associated with the interconnection of resources acquired in the Colorado Energy Plan Portfolio. The Mirasol Switching Station is located approximately 12 miles southeast of Comanche Substation, and intercepts one of the two Comanche – Midway 230 kV lines. The Tundra Switching Station is located approximately 13 miles northeast of Comanche Substation, and intercepts one of the two Comanche – Daniels Park 345 kV lines. The Commission issued a CPCN for these interconnection facilities in Proceeding No. 21A-0298E. The Tundra Switching Station was placed in service in May 2022 at a final cost of $21.9 million, and the Mirasol Switching Station was placed in service in April 2022 at a final cost of $22.8 million.

Comanche Substation – Sun Mountain Generation Interconnect (CEPP bid 077)

Public Service constructed interconnection facilities at the existing Comanche 230 kV Substation in Pueblo County to interconnect the 200 MW Sun Mountain Solar project to the Public Service transmission system. The interconnection facilities were put into service in September 2022 at a final cost of $1.7 million.

Greenwood -Denver Terminal 230 kV Transmission Project

Public Service constructed approximately 15 miles of new 230 kV transmission line between Public Service’s existing Greenwood and Denver Terminal substations (“GDT Project”). The line was needed to accommodate the Colorado Energy Plan Portfolio approved as part of Public Service's 2016 Electric Resource Plan. The new line was constructed by rebuilding existing transmission facilities from the Greenwood Substation to the Denver Terminal Substation within existing right-of-way. The existing Greenwood, Arapahoe, and Denver Terminal substations were all modified to accommodate the project. The Commission issued a CPCN for this project in the consolidated Proceeding Nos. 19A-0728E and 20A-0063E. Public Service files semi-annual project status reports in those proceedings. The project was placed in service in July 2023. Public Service is completing some final gas pipeline mitigation work along a portion of the GDT Project that parallels an existing gas line. The estimate at completion ("EAC") cost as of January 2024 is $102.7 million with no additional material costs expected.

CEPP Voltage/Reactive Support

The final remaining element of the CEPP Voltage/Reactive Support Facilities project, the STATCOM to control voltage flicker due to the CF&I (Evraz) arc furnace has been canceled based on updated studies that identified the project is not needed at this time based on current system conditions. All other voltage control facilities were placed in service in 2022 at a final cost of $67.3 million.

b. Planned Transmission Projects

i. 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.

Sandstone Switching Station

Public Service has identified, and is planning to pursue, a scope change for a discrete element of Colorado's Power Pathway Project driven by several factors that have arisen over the course of the Pathway Project's development, including challenges with the expansion of the Tundra Switching Station and the routing of Segment 5 in an area further east than initially anticipated. This scope change is primarily driven by siting and engineering factors rather than system planning considerations and will result in the development of an additional new switching station as part of the Pathway Project known as the Sandstone Switching Station. The new substation, which will be constructed in place of much of the originally planned expansion of the Tundra Switching Station, is not expected to materially affect the results of the transmission planning studies conducted in the development of the Pathway Project. Public Service identified and evaluated an alternative termination point for Segments 4 and 5 at a newly constructed switching station (*i.e. the* Sandstone Switching Station) located approximately 15 miles to the east of the Tundra switching station in Pueblo County. The expected final configuration will have the double circuit lines from May Valley (Segment 4) and Harvest Mile (Segment 5) terminate at the new Sandstone Switching Station, with the expansion of Tundra scaled back and a double circuit line connecting Tundra to Sandstone. In addition to the cost benefits for the Pathway Project, this new scope is also expected to create greater value by providing additional resource interconnection points in Pueblo County ahead of Public Service's next resource solicitation in the Just Transition Plan. Public Service has not identified any ATTs that are suitable alternatives to the construction of the Sandstone Switching Station, as this planned transmission project's need is driven by siting and engineering-related changes to the scope of the Pathway Project and no ATTs were determined to be suitable alternatives to the Pathway Project. Public Service anticipates making a regulatory filing seeking Commission approval of the Sandstone Switching Station in early 2024.

ii. Planned Transmission Projects (Included in Previous Rule 3627 Filings)

Colorado's Power Pathway

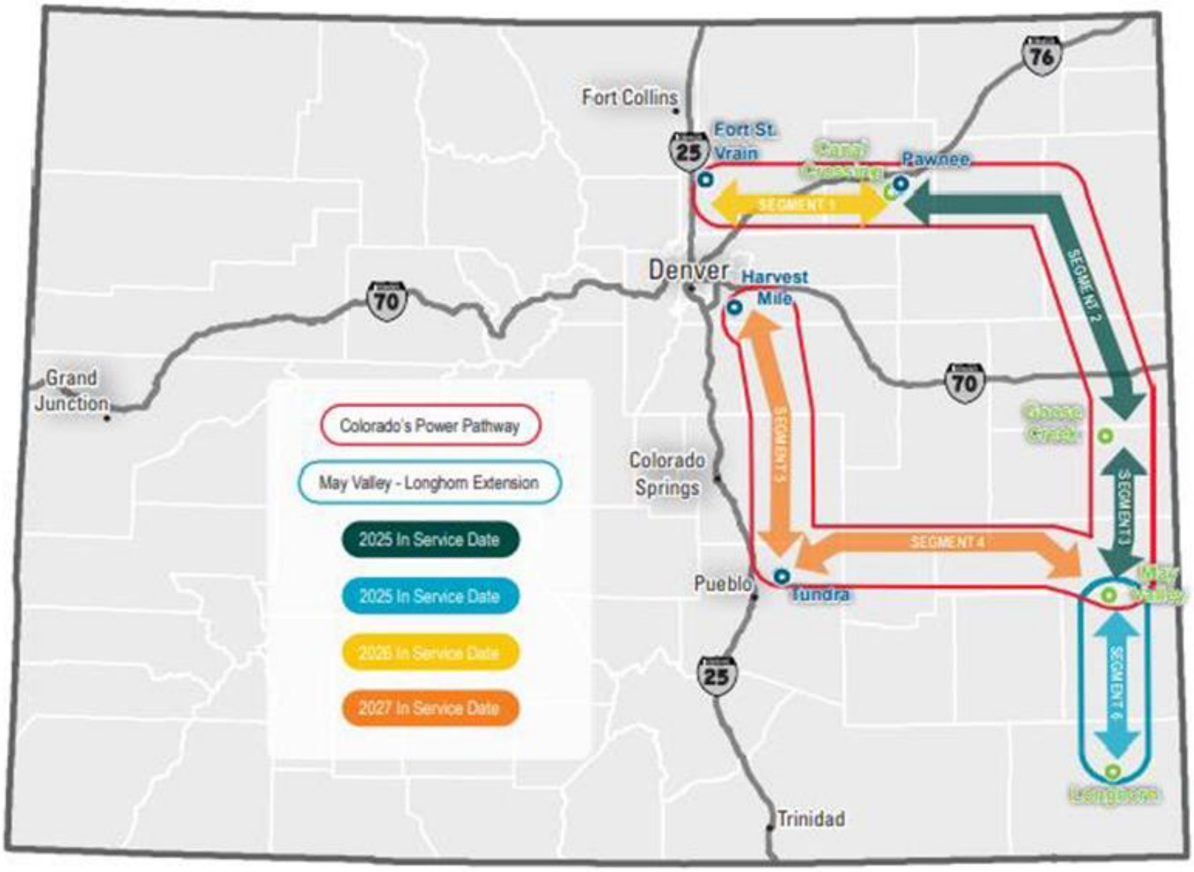
Colorado's Power Pathway is a 345 kV transmission project planned as a means to deliver an estimated 3,000-3,500 MW of simultaneous power output from new renewable energy resources located in eastern and southern Colorado. The primary driver for Public Service is to meet 80 percent carbon reduction from 2005 carbon levels by 2030 consistent with the State's statutory Clean Energy Plan mandate. The project was identified within the 80x30 Task Force as a part of the Colorado Coordinated Planning

Group. The project consists of approximately 560 miles of double circuit 345 kV lines for providing transmission access to ERZs 1, 2, 3, and 5, and connecting them to the Denver Metro Area. A CPCN was approved by the Commission in 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
- Segment 1: 345 kV double-circuit transmission line between Canal Crossing and Fort St. Vrain
- Segment 2: 345 kV double-circuit transmission line between Canal Crossing and Goose Creek
- Segment 3: 345 kV double-circuit transmission line between Goose Creek and May Valley
- Segment 4: 345 kV double-circuit transmission line between May Valley and Tundra
- Segment 5: 345 kV double-circuit transmission line between Tundra and Harvest Mile

The project also includes an optional Longhorn Switching Station in Baca County that would be connected to the May Valley Switching Station 345 kV double circuit transmission line between May Valley and Longhorn. The Commission granted a conditional CPCN for the May Valley – Longhorn Extension in Proceeding No. 21A-0096E; however, the May Valley – Longhorn Extension was not selected in the portfolio approved by the Commission in Decision No. C24-0052 in Public Service's 2021 ERP & CEP in Proceeding No. 21A-0141E. Public Service may propose construction of the May Valley – Longhorn Extension at a future date.

Figure 7.



Public Service considered storage resources as a potential alternative to transmission facilities comprising the Pathway Project. However, it quickly became evident that, fundamentally, storage does not offer a reasonable alternative to this project from a technical or practical perspective. Other ATTs were not relevant to the Pathway Project's goal of delivering remotely located resources to Public Service's load centers. Public Service's analysis of ATTs for the Pathway Project was discussed in detail in the CPCN proceeding.

While conductor type is not typically within the scope of the transmission planning process, Public Service also evaluated HTLS conductors in its engineering of the Pathway Project in addition to the evaluation of ATTs and NWAs in the planning process. Public Service selected a conventional conductor technology as it is the most cost-effective engineering solution to meet the identified planning need. Public Service filed a detailed report in Proceeding No. 21A-0096E showing the analysis of alternative conductor types which demonstrated that the benefits of advanced HTLS conductor technologies did not outweigh the incremental costs of deploying those conductors on the Pathway Project.

The Pathway Project is estimated to cost approximately $1.685 billion and in-service dates for the segments ranging from 2025 to 2027. The Pathway Project is currently under construction, and Public Service files semi-annual progress reports in Proceeding No. 21A-0096E.

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 Public Service 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 Public Service 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. Due to the need to replace the 44kV transmission assets, Public Service and CCPG Northeastern Colorado ("NECO") Subcommittee determined that an energy storage alternative would not mitigate the need to improve the existing transmission infrastructure in the area. The project was granted a CPCN and is currently under construction with a planned in-service date of 2024.

Stagecoach Switching Station

A new 230 kV switching station is needed to connect GI-2014-9, a 70 MW photovoltaic 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." Because this planned project is for the interconnection of a generator to Public Service's transmission system, Public Service did not conduct a detailed analysis of ATTs or energy storage as these solutions are not capable of providing the needed physical connection to the system. The planned in-service date is 2025 and a CPCN may be needed.

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 in the event of a sustained outage condition. Energy storage was determined not to be a viable solution to effectively mitigate the NERC reliability criteria for specific violations. However, the conductor selection will be analyzed based on the desired electrical performance and system feasibility for this specific area during the project engineering process. The project does not require a CPCN and has a planned in-service date of 2027, though Public Service notes that routing and permitting issues may affect the planned in-service date.

c. Conceptual Transmission Projects

The following transmission projects are considered conceptual in nature, as Public Service has not yet completed adequate planning and analysis to consider a project planned. In general, Public Service does not consider a transmission project to be "planned" until it has gone through corporate governance processes that internally approve project scopes, budgets, and timelines signifying that Public Service is committed to developing the project. Conceptual projects typically have different levels of refinement and confidence based on the work that has been completed to date – for some projects, a planning need may have been preliminarily identified but alternative solutions have not yet been thoroughly vetted through the transmission planning process, whereas for others, Public Service may have completed its transmission planning analysis and identified a preferred solution but has not yet developed adequate project scopes, budgets, and timelines based on specific engineering, procurement, and siting and permitting information relevant to the project. Project in-service dates can vary depending 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.

i. New Conceptual Transmission Projects

<u>Network Upgrades</u>

Leetsdale – Elati 230 kV Circuit 5283 Underground Transmission Line Upgrade

The underground Leetsdale – Monroe – Elati 230 kV Circuit 5283 transmission line was derated in 2022 based on a facility rating update study for the circuit. Because of the substantial derate (>20 percent), the line frequently experiences post-contingency (N-1) overloads under certain system operating conditions and is a transmission capacity constraint (i.e. congestion) for higher renewable generation imports in the Denver Metro area. The line derate will become an even more challenging transmission congestion problem with higher renewable generation imports into the Denver Metro area from the 2021 ERP & CEP and the scheduled retirement of the Cherokee 4 generator in 2027.

A transmission project is necessary to mitigate existing, as well as expected future, transmission congestion challenges. Public Service's preliminary analysis has identified that upgrading the existing oil-filled cable used on this circuit with a new cross-linked polyethylene cable would alleviate overloads of the circuit. Because of the location of the Leetsdale – Monroe –Elati 230 kV transmission line in central Denver, Public Service's alternatives to address the overload of this circuit are limited due to urban congestion, or lack of available space, within the Denver Metro area. There is limited space in which

Public Service can develop new lines that address overloading of this circuit. Any such line will likely need to be constructed underground.

Public Service is conducting detailed evaluations of the suitability of ATTs and NWAs for this project as alternatives to the construction of a replacement transmission line and expects to engage with stakeholders through the FERC Order 890 local transmission planning process in 2024 before finalizing the project's scope and identifying a planned transmission project. Public Service is skeptical that an energy storage solution could address the reliability issues associated with an overload on this circuit given the operational constraints of currently available storage technologies and the nature of the overloads that this circuit will experience; however, Public Service is preparing a more detailed analysis of energy storage, a series reactor, and phase shifting transformers technologies to validate whether these ATTs have the potential to be cost-effective solutions, in whole or in part, in conjunction with or compared to a traditional project.

2021 ERP & CEP Transmission Network Upgrades

For Phase II of Public Service's 2021 ERP & CEP, Public Service's Transmission team conducted its most thorough transmission analysis to accompany an ERP to date. The projects listed in this section of the Ten-Year Plan are the projects that Public Service identified as needed to support the Preferred Plan in the 120-Day Report and accompanying Phase II Transmission Plan filed in Proceeding No. 21A-0141E.

The transmission planning process implemented in Phase II of the 2021 ERP & CEP, and the transmission projects identified in this section, were developed to carefully balance the needs of Public Service's Preferred Plan with an eye toward future system growth and the increasing difficulty of siting, permitting, and constructing large-scale transmission solutions in Colorado's population centers. The projects identified in this section of the Ten-Year Plan are designed to take maximum advantage of Public Service's existing transmission facilities. Wherever possible, Public Service sought to expand transmission capacity by upgrading existing transmission facilities starting with the least invasive and the most cost-effective projects to meet customers' needs. Public Service's analysis identified significant transmission expansion needs in the Denver metro area, driven in large part by the shift in the location of Public Service's generation resources from primarily within the metro area to predominantly remote areas. Public Service also sought to develop a portfolio of projects that balanced both present and reasonably foreseeable future needs. While a smaller transmission expansion plan may have alleviated transmission overloads within a short time window, the customer value of a smaller transmission portfolio would be quickly overwhelmed by additional load growth and resource acquisitions, requiring costly and difficult upgrades to new transmission facilities. The conceptual projects identified in this section of the Ten-Year Plan are effective in balancing these needs.

Public Service identified transmission projects by evaluating transmission system performance across a range of scenarios. For each case analyzed, power flow contingency analysis results were produced for system performance criteria thermal and voltage violations during system intact (N-0) and single contingency event (N-1) analysis. The thermal violations represent the transmission capacity limiting facilities. Thermal (capacity) violations attributed to station equipment ratings are mitigated by replacing the limiting element(s) within the substation. Thermal (capacity) violations that are transmission line conductor rating limited are mitigated by reconductoring or rebuilding the line as applicable, or by identifying a transmission expansion alternative that mitigates multiple thermal violations by providing an additional transmission path in the network. ATTs and NWAs were considered as potential solutions in this planning process. Public Service also conducted a tabletop analysis of the identified projects to develop preliminary project scopes, determine the feasibility of the projects, make early adjustments or refinements to project scopes as needed, identify and account for potential project risks that could be encountered in the development of each transmission project, and develop preliminary cost estimates for projects. This initial project scoping process also evaluated, and in several cases identified as a preferred engineering solution, the use of HTLS conductors for transmission line projects. Public Service provided more detail of the transmission planning analysis and project scope development in its Phase II Transmission Report, included as Appendix Q to Public Service's 120-Day Report filed in Proceeding No. 21A-0141E.

However, while Public Service has conducted a rigorous analysis to develop each of these projects, they are considered “conceptual” in this Ten-Year Plan because they have not yet been fully evaluated through the stakeholder-driven transmission planning process pursuant to Rule 3627 and FERC Order No. 890 and also are inherently dependent on the outcome of the Commission’s pending Phase II decision approving a resource portfolio. Public Service will be in a position to move forward with this coordinated planning process once a final Phase II decision for the 2021 ERP & CEP is in place.

Public Service will continue to engage with stakeholders as it evaluates what transmission expansion is needed to support its approved Clean Energy Plan. Public Service intends that its planning process will be forward-looking based on both selected resources in 2021 ERP & CEP as well as future transmission needs to avoid “just in time” planning and deploy transmission ahead of future expected resource acquisitions. This process also will more thoroughly evaluate the potential role of ATTs, as cost-effective enhancements or alternatives to traditional transmission designs. The resulting transmission planning studies will be presented to the Commission in applications for CPCNs as appropriate and consistent with the final Phase II decision.

Greenwood Substation Bus Tie Uprate

This project consists of replacing several limiting elements on the 230 kV bus to achieve a 2000-amp rating.

Arapahoe 115 kV Bus Uprate and Second 230/115 kV Transformer

This project consists of replacing all limiting elements on the 115 kV bus to achieve a 2000-amp rating and installing a new 280 MVA 230/115kV transformer and associated equipment to connect the transformer within the yard.

Chambers Third 230/115 kV Transformer

This project consists of installing a 3rd 280 MVA 230/115 kV transformer at the Chambers substation. As there is no room to complete this project at the existing Chambers substation, the project is expected to require the construction of a new substation near the Chambers substation. The new substation will be 230/115 kV and house all three 230/115 kV transformers while the existing Chambers substation will house the 115 kV yard. The new substation near Chambers also allows for additional connections needed on other identified projects.

Daniels Park to Greenwood Circuit 5707 Uprate

This project consists of reconductoring 8.4 miles of circuit 5707 to achieve a 756 MVA rating and replacing substation elements that do not meet the required rating. This project is expected to use HTLS conductor.

Daniels Park to Greenwood Circuit 5111 Uprate

This project consists of reconductoring 8.4 miles of circuit 5111 to achieve a 756 MVA rating and replacing substation elements that does not meet the required rating. This project is expected to use HTLS conductor.

Phase Shifting Transformer on Missile Site to Daniels Park 345 kV Circuit 7109

This project consists of installing a 345 kV 650 MVA with an estimated +/ 60 degrees phase shifting transformer in a new station near Missile Site along the 7109 right of way and installing required transmission lines to connect to the new station.

230 kV Circuit 5165 In and Out of Harvest Mile

This project consists of bringing 230 kV circuit 5165 in and out of the existing Harvest Mile Substation and installing 230 kV equipment within the existing Harvest Mile Substation to connect the new circuit. This in and out connection is expected to be underground based on routing congestion between the existing 5165 circuit and Harvest Mile Substation.

New Double Circuit 230 kV Line from Harvest Mile – Chambers – Sandown – Cherokee

This project consists of installing a new double circuit 230 kV line with a required rating of 3000 amps on each circuit, with a preliminary assumed length of 8 miles of overhead lines and 19.3 miles of underground lines. The lines would be constructed as 345 kV capable; however, future conversion to 345 kV operation would require installation of an additional duct bank.

For the substations, Public Service anticipates an expansion/new location will be required at Harvest Mile to fit the 230 kV connections. As discussed for the Chambers Third 230/115 kV Transformer project, a new 230 kV substation near Chambers is already contemplated and is also required for this project. At Sandown there is currently no 230 kV equipment or space for expansion, so Public Service anticipates that a new station will be required near Sandown for the 230 kV connections. At Cherokee station there is space within the existing yard to build out the facilities required to connect the new lines.

Uprate Substations on Circuit 9811 Poncha Junction and San Luis Valley

This project consists of replacing 115 kV limiting elements at Poncha Junction and San Luis Valley Substations to achieve facility ratings equal to the 1250-amp line conductor rating.

Uprate Substations on Circuit 3006 Poncha West and San Luis Valley

This project consists of replacing 230 kV limiting elements at Poncha West and San Luis Valley Substations to achieve a 1200-amp rating. This project will require coordination with WAPA and Tri-State as the terminal owners.

Tollgate Substation Load Shift

This project consists of moving the 230 kV Tollgate Substation source from circuit 5285 to circuit 5167 and replacing limiting elements at each substation on circuit 5285 to achieve a 1266-amp rating.

Uprate Substations on Circuit 5057 Cherokee and Lacombe

This project consists of replacing 230 kV limiting elements at Cherokee and Lacombe Substations to achieve a 2200-amp rating.

Havana to Chambers Circuits 9543 and 9544 Uprate

This project consists of rebuilding 115 kV circuits 9543 and 9544 between Havana and Chambers substations to achieve a 1600-amp rating. Consideration was given to reconductoring both circuits, but the existing lattice towers are not able to support a large enough conductor to meet the required rating. This project also consists of replacing limiting elements at Havana Substation to meet the 1600-amp requirement.

Malta to Poncha Junction Circuit 9255 Uprate

This project consists of rebuilding 32 miles of 115 kV circuit 9255 between Poncha Junction and Otero Tap Substations to achieve a 1200-amp rating. The section between Otero Tap and Malta Substations will have already achieved this rating by completion of an existing project. For the rebuilt section, Public Service would rebuild the structures to be 230 kV capable. This project also includes replacing limiting elements at Malta Substation and Poncha to achieve the required rating.

Daniels Park Fourth Transformer

This project consists of installing a fourth 560 MVA 345/230 kV transformer at Daniels Park Substation. This installation may require the acquisition of additional land. Currently, land surrounding the Daniels Park substation is designated as open space, which presents additional challenges and potential cost to the scope and complexity of the project.

Smoky Hill Third Transformer

This project consists of installing a third 560 MVA 345/230 kV transformer at Smoky Hill Substation.

Leetsdale to Harrison 115 kV Circuit 9955 Uprate

This project consists of rebuilding 3.5 miles of 115 kV circuit 9955 from Leetsdale to Harrison to achieve a 756 MVA rating, removing existing HPFF underground circuit, and building a new XLPE circuit in a new concrete duct bank. This project also includes installing a 230 kV capable conductor for future voltage conversion and uprating limiting elements at Leetsdale and Harrison Substations to achieve the required ratings.

Capitol Hill to Denver Terminal 115 kV Circuit 9007 Uprate

This project consists of rebuilding 2.5 miles of 115 kV circuit 9007 from Capitol Hill Substation to Denver Terminal Substation to achieve a 756 MVA rating, removing existing HPFF underground circuit and building a new XLPE circuit in a new concrete duct bank, and installing a 230 kV capable conductor for future voltage conversion. This project also includes uprating limiting elements at Capitol Hill and Denver Terminal Substations to achieve the required ratings.

Midway Substation 230 kV Bus Uprate

This project consists of replacing limiting elements on the 230 kV bus tie at Midway substation to achieve a 2400-amp rating.

Midway Substation 230/115 kV Transformer Replacement

This project consists of replacing an existing 230/115 kV transformer with a 280 MVA 230/115 kV transformer.

Cherokee to Broomfield 115 kV Circuits 9055/9558/9464 Uprate

This project consists of rebuilding 13 miles of double circuit 115 kV lines 9005/9558/9464 to achieve a 2000-amp rating. Consideration was given to reconductoring both circuits. However, the existing wood structures, previously modified from 1 to 2 circuits, are not able to support a large enough conductor to meet the required rating. This project also requires the replacement of limiting elements at Cherokee, Semper, and Broomfield Substations to meet the 2000-amp requirement.

Leetsdale to University 115 kV Circuit 9338 Uprate

This project consists of reconductoring one mile of 115 kV circuit 9338 to achieve a 1268-amp rating and replacing substation elements that do not meet the required rating. This project is expected to use an HTLS conductor.

San Luis Valley 115 kV Circuit 9431 Uprate

This project consists of replacing limiting elements at the San Luis Valley substation to achieve an 800-amp rating.

Alamosa to Mosca to San Luis Valley 69 kV Circuits 6935/6936 Uprate

This project consists of replacing limiting elements at the San Luis Valley, Mosca, and Alamosa Plant substations to achieve an 800-amp rating. Additionally, Public Service will rebuild 0.2 miles of line 6935. (The remaining 24 miles of circuit 6935 and 6936 have previously been rebuilt.)

New 115 kV Line San Luis Valley to Alamosa Terminal

This project consists of constructing a new 115 kV circuit between the existing San Luis Valley and Alamosa Terminal Substations with a 1200-amp rating. The new line is assumed to be on a new 75-foot easement, single pole steel construction, 477 kcmil ACSS "Hawk" conductor matching the rest of the 115 and 69 kV system in the San Luis Valley. This project also includes the expansion of the Alamosa Terminal substation within the existing yard to accept the new 115 kV line and the construction of a new substation near the existing San Luis Valley Substation to accept the new 115 kV line, as the existing 115 kV yard does not appear to be able to accept the new line. Public Service will coordinate with Tri-State to determine the final viability of expansion compared to a new substation.

Interregional Transmission Capacity Expansion

Lamar DC Tie Upgrade

The Lamar HVDC back-to-back converter station is a 210 MW bi-directional traditional six pulse line commutated converter that provides for the transfer of electricity between the Eastern Interconnection and Western Interconnection electric grids. This DC tie was originally placed in-service in 2004 and serves as an asynchronous connection between Public Service and SPS, an affiliate Xcel Energy utility operating company that serves retail customers in Texas and New Mexico. The station is located approximately 14 miles northeast of the town of Lamar, Colorado. The station is currently being evaluated for replacement due to several subsystems reaching or exceeding their expected useful life. As part of the replacement, Public Service is also evaluating opportunities to expand the capacity of the DC tie to take advantage of greater interregional connections and broader access to energy markets in the Eastern Interconnection. Public Service currently anticipates that this project will be studied with input from the CCPG subregional planning area and the adjacent Southwest Power Pool regional planning area.

ii. Previously Reported Conceptual Transmission Projects

Weld–Rosedale–Box Elder–Ennis Transmission

Public Service has been working through the CCPG Northeastern Colorado Subcommittee ("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 should also align with other planned transmission projects in the area, including the Ault-Cloverly Project. 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 and the corporate governance approval to construct the project, and Public Service will bring forward an application for a CPCN when it is prepared to seek Commission approval.

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. This expansion 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. In general, the Weld County Expansion conceptualizes an increase in transmission capability between the planned Ault – Cloverly project, the conceptual Weld – Rosedale – Box Elder – Ennis project and the northern Denver metro area. This transmission expansion could enable increased north to south transfers into the Denver metro area and potentially remove operating limitations associated with the WECC TOT 7 path. Further, this project could potentially improve import and export capability between Public Service and northern systems. Finally, the conceptual transmission expansion in Weld County could allow for an increase in load serving capability as well as an increase in generation accommodation to meet clean energy goals.

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 projections and reliability needs. A separate program exists to address the condition of the assets due to wildfire risk.

Carbondale – Crystal Transmission

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

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

Like Tri-State, Public Service 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 accomplishing some of the area's reliability needs. Additional transmission beyond Poncha to the Front Range would not only 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 Clean Energy Plan goals. Due to a renewed interest in the San Luis Valley, the SLVTF and interested stakeholders are in the process of updating past studies and refreshing the transmission alternatives in the area.

Colorado's Power Pathway Project Voltage Control / Reactive Support and Grid Strengthening

Public Service expects that the substantial amount of new generation interconnected to the Pathway Project will require a variety of 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 may also 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 bid solicitation process. The planned facilities will be determined after its Clean Energy Plan is approved and the locations and sizes of resource acquisitions are known.

Interregional Transmission Capacity Expansion

Northern Colorado Transmission

Public Service is conceptually exploring how to enhance the bi-directional power transfer capability into the Public Service system with neighboring regional entities. 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 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.

d. Other Long-Range Distribution Planning Substation Projects

Below is a list of substation projects under consideration by Public Service. Public Service, the Office of the Utility Consumer Advocate, ("UCA") and Staff of the Colorado Public Utilities Commission ("Staff") agreed through discussions related to Proceeding No. 14A-1002E to identify potential new distribution substation sites in rapidly growing areas. While the terms of the agreement between Public Service, UCA, and Staff have expired, Public Service continues to provide a list of distribution-driven substation projects for informational purposes only and as a supplement to the reporting requirements under the Commission's Distribution System Planning rules. Public Service is not seeking Commission determination of the need for CPCNs for these projects or any Commission action at this time. In-service dates and estimated costs for most of these projects are TBD based on ongoing analyses of project needs, scopes, and schedules. The estimated costs provided in this table are only for the transmission facilities associated with these projects and do not include the cost of any distribution facilities that would be constructed.

Table 9. Long-Range Distribution Planning Substation Projects

Substation Project Name	Transmission Voltage	Approximate Location	Potential ISD	Estimated Cost ($ millions)
Metro Water Recovery Substation (100% customer funded)	115 kV	Adams County	2024	$16
Poder Distribution Substation[17]	115 kV	Elyria-Swansea, City and County of Denver	2026	$5.9
Kestrel Substation[18] (100% customer funded)	230 kV	Aurora, Adams and Arapahoe County	2026	$28.1
Barker Distribution Substation	230 kV	Lower Downtown, Denver	2027	TBD
Berkley Distribution Substation	TBD	Berkley, Denver	TBD	TBD
Blue Spruce Distribution Substation	230 kV	Adams County	TBD	TBD
Dove Valley Distribution Substation	TBD	Arapahoe County	TBD	TBD
Gray Street Distribution Substation	230 kV	Lakewood, Jefferson County	TBD	TBD
Lowry Distribution Substation	TBD	City and County of Denver	TBD	TBD
Wilson Distribution Substation	115 kV	Loveland, Larimer County	TBD	TBD

[17] This project also has been referred to as the Stock Show Substation in previous reporting.

[18] This project also has been referred to as Project Bronco and the QTS Transmission Facilities in previous filings.

Solterra Distribution Substation	230 kV	Lakewood, Jefferson County	TBD	TBD
New Castle Distribution Substation	69 kV	New Castle, Garfield County	TBD	TBD
North Sheridan Distribution Substation	TBD	Lakewood, Jefferson County	TBD	TBD
Superior Distribution Substation	115 kV	Superior, Boulder County	TBD	TBD
Sandy Creek Distribution Substation	230 kV	Arapahoe County	TBD	TBD
Wellington Distribution Substation	TBD	Wellington, Larimer County	TBD	TBD

IV. Projects of Other CCPG Transmission Providers

In addition to the projects planned by Black Hills, Tri-State, and Public Service contained in this 2024 Plan, a thorough understanding of all transmission projects planned in Colorado requires consideration of projects planned by other utilities and TPs.

Table 10. Colorado Springs Utilities Projects

In-Service	Project Name	Description	Purpose
2023	North System Improvements	Briargate Sub Expansion and 230/115kV Autotransformer Intercept Fuller-Cottonwood 230kV Line Fuller-Cottonwood Line Uprate	Reliability
2024	Nixon-Kelker 230 kV Line Uprate	Increase clearance on Nixon-Kelker 230 kV line to increase facility rating on the line.	Increase facility rating
2024	Pike Solar	175 MW Solar PV Project Interconnection – Williams Creek Substation	Generator interconnection – renewable PPA
2024	Kettle Creek Transformer	Kettle Creek 115/12.5kV Power Transformer Addition	Load serving

In-Service	Project Name	Description	Purpose
2024	Flying Horse Flow Mitigation	Install Series Reactor on Flying Horse-Monument 115kV Line Section to Mitigate Inadvertent Power Flows	Reliability
2024	Fuller Transformer	Fuller 230/12.5kV Power Transformer Addition	Load serving
2024	Horizon Substation and Transformer	New Horizon Substation and Transformer Addition	Load serving
2025	Fuller BESS	100 MW Battery Energy Storage Project Interconnection – Fuller Creek Substation	Interconnection – Energy Storage PPA
2026	Claremont Transformer	Claremont 230/34.5kV Power Transformer Addition	Load serving
2026	Flying Horse Transformer	Flying Horse 115/12.5kV Power Transformer Addition	Load serving
2027	Central System Improvements	New Kelker-South Plant 115kV Line Rebuild Kelker Substation to Full Breaker and a Half (230 and 115kV)	Reliability
2027	South System Improvements	Midway-Kelker 230kV Transmission Line	New Transmission Line

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 11. Platte River Power Authority Projects

In-Service	Project Name	Description	Purpose
2024	Severance Solar (SEV) 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 12. Western Area Power Authority Projects

In-Service	Project Name	Description	Purpose
2027	Fort Morgan Capacitor Bank Replacement Project	Replace existing 15MVAR cap bank with larger 45 MVAR bank to provide additional area voltage support.	Replacing aging equipment and increasing size
2030	Weld KV1A	Replace KV1A at Weld due to condition/age. Convert to breaker and half to increase reliability.	Replace aging equipment and increasing size
2032	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.

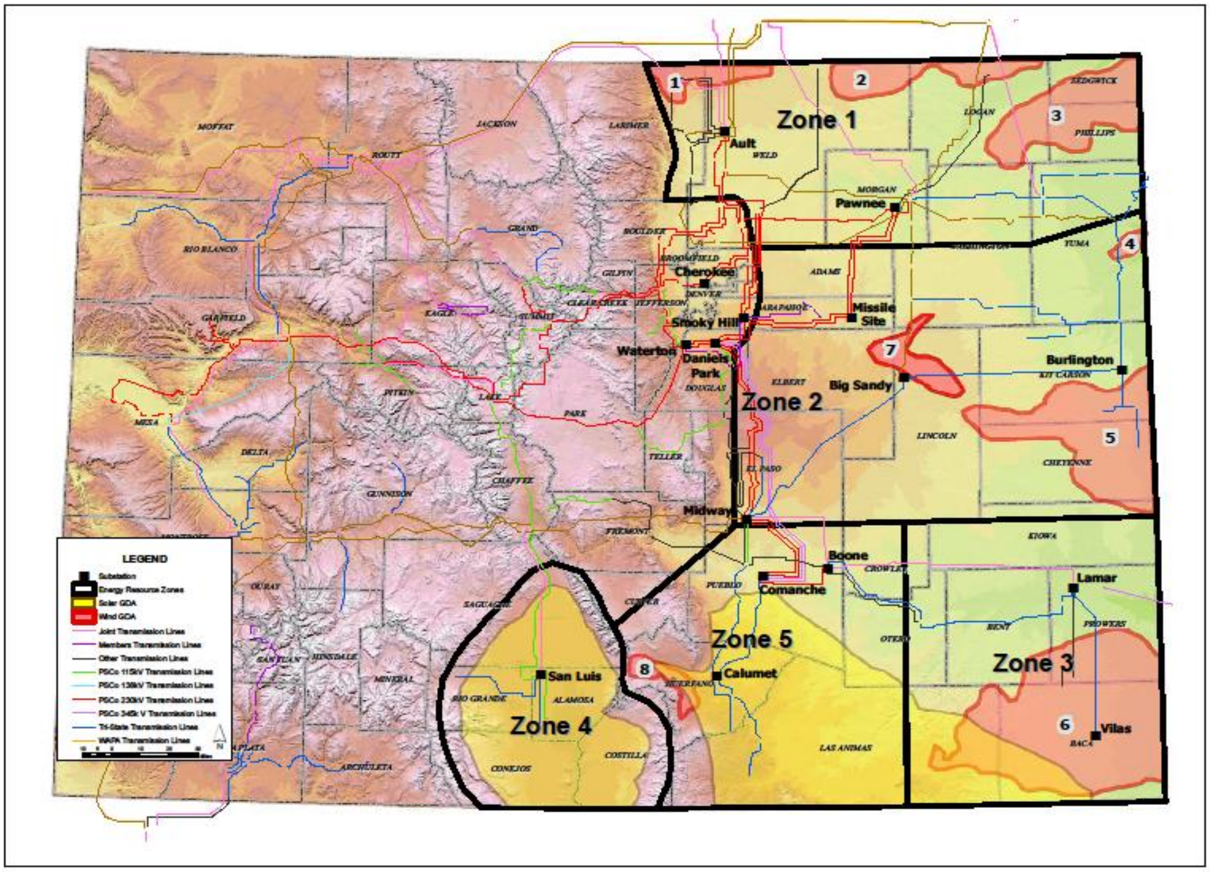
ERZ 4 (San Luis Valley)

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 encourages all interested parties to participate in the 2023 SB07-100 study process. An open stakeholder meeting was held in Q1 as part of the Black Hills Colorado Transmission ("BHCT") Transmission Coordination and Planning Committee ("TCPC") on March 16, 2023, to inform stakeholders of the regulatory efforts of SB07-100 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 routine study work performed by Black Hills. These meetings occurred June 30, 2023, September 26, 2023, and December 15, 2023, respectively. 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/.

For the 2023 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 using a 2034 Heavy Summer ("HS") because to identify any adverse impact to the reliability and operating characteristics of the Western Electricity Coordinating Council ("WECC") bulk electric 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 injection of new generation on area transmission reliability.

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. Area interchange control was disabled and generator VAR limits were applied immediately for all solutions. The solution method implemented was a full Newton-Raphson solution.

Black Hills SB07-100 Conclusions

Black Hills utilized an open and transparent process in conducting its 2023 Colorado Senate Bill 07-100 study. Stakeholders were provided 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 115 kV Substation: The 2034HS study results indicated that the BHCE transmission system could accommodate a 125MW injection at the Baculite Mesa 115kV substation with minor sub-transmission upgrades or changes. 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 115 kV Substation: Additionally, the study results indicated that the BHCE transmission system could accommodate a 175MW injection at the Boone 115kV substation. Higher levels of injection into this substation causes overloads on Public Service's Boone 230/115kV transformer during the N-2 contingency of the Boone – Nyberg 115 kV line & the Boone – Dot Tap – Nyberg 115 kV line.

Greenhorn 115kV Substation: This cycle for the SB07-100 evaluated generation injection at the Greenhorn 115 kV substation. Since this substation has a single transmission line in and out, the amount of generation that can be injected is limited to 200 MW on the Greenhorn – Burnt Mill 115 kV line for the N-1 loss of the Greenhorn – Reader 115 kV line. Distribution load local to the Greenhorn and Burnt Mill 115 kV substations directly impacts the amount of generation that can be injected.

Hogback 115 kV Substation: This study also evaluated injections at the newly constructed Hogback 115kV substation. The results indicated that the BHCE transmission system could accommodate a 100MW injection at this location. Injection limits into this area may vary greatly depending on local Canon City distribution load, Turkey Creek PV generation output, and proposed transmission upgrades that may occur in the next five to ten years. As injections increased beyond the 100 MW value, overloads were observed on the Canon West 230/115 kV transformer and the West Station – Turkey Creek 115 kV line.

Reader 115 kV Substation: The analysis indicated that the Reader 115 kV substation could allow for 140 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 and new renewable generation injected at Comanche. As generation in the area increases, the risk of overloads in the area will increase following the loss of the Comanche – Tundra double 345 kV circuits. In this analysis, flow through the Pueblo 115 kV system was at its peak during this N-2 contingency. This occurs as losing the 345 kV backbone from Comanche to the Denver area load causes the generation to flow through the underlying 230 and 115 kV systems.

South Fowler 115 kV Substation: This study indicated that 175 MW of generation can be injected at the South Fowler 115 kV substation. The results of this analysis are identical to the Boone 115 kV substation analysis as higher levels of injection into this substation causes overloads on Public Service's Boone 230/115kV transformer during the N-2 contingency of the Boone – Nyberg 115 kV line & the Boone – Dot Tap – Nyberg 115 kV line.

West Station 115 kV Substation: The last injection point that was included in the analysis was the West Station 115 kV substation. The results indicated that the BHCE transmission system could accommodate a 175 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 address limiting substation equipment has increased the rating on the line when compared to previous years' studies. However, during this cycle the N-2 345 kV contingency from Commanche to Tundra previously described causes overloads on the West Station – Desert Cove 115 kV line with injections more than 175 MW.

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 are 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 13.

Public Service has completed the first five projects listed in Table 13. These projects have enabled Public Service to interconnect 1,400 MW of wind in eastern and northeastern Colorado and accommodates an additional 600 MW of wind from the Rush Creek Wind Project. The Commission issued a CPCN for the Colorado's Power Pathway Project in Proceeding No. 21A-0096E, and the project is currently under construction. 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 13. 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 granted on June 2, 2022. Project under construction.
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
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 Substation (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 345 kV 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 a stepping stone to facilitate construction of the Pawnee-Daniels Park 345 kV Project. The Limon Wind Energy Center brought about 600 MW (nameplate) of wind generation into Missile Site in 2014, and in 2018, the Rush Creek Project added another 600 MW (nameplate). The Bronco Plains and Cheyenne Ridge projects interconnected another 800 MW (nameplate), combined, in 2020.

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

The Pawnee-Daniels Park 345 kV Transmission Project is described in Section III.C.3. 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 a total cost of $174.6 million.

2. Projects Under Construction

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

The Colorado's Power Pathway Project ("Pathway Project") is described in Section III.C.3. The Commission issued a CPCN for the Pathway Project in Proceeding No. 21A-0096E. The Pathway Project consists of building approximately 550 miles of double circuit 345 kV transmission lines along with four new substations and the expansion of four existing substations. The project will connect the Front Range to areas of northeastern, eastern, and southern Colorado that are rich with renewable resource potential but do not have a backbone network transmission system sufficient to integrate new clean energy resources. The project will interconnect to the Fort St. Vrain and Harvest Mile Substations within the Denver Metro Area. The Commission conditionally approved an additional transmission segment from the new May Valley substation at the southeastern corner of the Pathway project to a new Longhorn station in Baca County, known as the May Valley – Longhorn Extension, but the May Valley-Longhorn Extension was not included in the resource portfolio approved by the Commission in Decision No. C24-0052 in Public Service's 2021 ERP & CEP in Proceeding No. 21A-0141E. Public Service may propose the construction of the May Valley – Longhorn Extension at a future date. 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 May Valley – Longhorn Extension cost is estimated at approximately $250 million, though this cost is expected to increase due to higher land, material, and labor costs if the project is delayed.

3. Conceptual Projects

Weld County Transmission Expansion (ERZ-1)

This plan is described in Section III.B.3 as a means to accommodate additional generation resources in ERZ-1. CCPG's NECO Subcommittee has been working to develop a comprehensive transmission plan for Northeast Colorado to serve a variety of needs. In order to replace aging 44 kV infrastructure that serves Public Service's customers in Weld County while accommodating load growth and potential generation development, transmission upgrade projects have been planned and are being developed in the area that align with and may ultimately replace or subsume the Weld County Expansion Project. Public Service is implementing the Ault-Cloverly 230/115kV Project, also known as the Northern Colorado Area Plan ("NCAP") Project, to replace the 44 kV transmission system in northern Weld County. The NECO Subcommittee is currently evaluating project alternatives to replace the 44 kV system in central and southern Weld County with final study results expected in early 2024. The Weld County Expansion may be a new project that could be considered as a third phase of the planning efforts in the area that focuses on linking the NCAP Project with the transmission project identified for central and southern Weld County and creating greater links to the transmission system in the Denver metro area.

Public Service will continue to work with stakeholders through the NECO Subcommittee to study and identify specific projects in this region, coordinate projects with other utilities, and develop plans for implementation.

San Luis Valley (ERZs 4 and 5)

This plan has been described in Section III.B.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. CCPG's San Luis Valley Subcommittee ("SLV Subcommittee") was established to evaluate transmission projects in this region of the state and conducted its initial planning activities in 2016 and 2017. The SLV Subcommittee's Phase 1 study, completed in 2016, concluded that increasing the capacity out of the San Luis Valley requires, at a minimum, an additional 230 kV line to meet system reliability criteria. The Phase 2 study, completed in 2017, was focused on how best to leverage the additional 230 kV line for increased generation export capability from San Luis Valley to the Denver-Metro area. In 2022, the SLV Subcommittee and interested stakeholders re-ignited efforts to update past studies and refresh the evaluated transmission alternatives in the area.

Public Service will continue to engage with stakeholders through the CCPG San Luis Valley Subcommittee to study and recommend specific transmission projects in the region, coordinate projects with other utilities, 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 2023 as part of Black Hills' annual TCPC process. The primary kickoff took place on March 16, 2023, and the second, third and fourth invites occurred on June 30, 2023, September 26, 2023, and December 15, 2023. 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. 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 also held via phone/web conference. 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 via phone/web conference and served the purpose of this meeting of reviewing the 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 2023 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 2024 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 2023, Tri-State hosted one transmission planning-related stakeholder outreach meeting in connection with development of the 2024 10-Year Transmission Plan. The meeting was held on November 20, 2023, and provided a summary of 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 November 2023.

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. In 2020, 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 2024 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 2024 10-Year Transmission Plan.

C. Public Service Outreach Summary

Rule 3627 requires a summary of stakeholder participation and input and how this input was incorporated in the transmission plan. The rule states that government agencies and other stakeholders shall have an opportunity for meaningful participation in the planning process. The government agencies include affected federal, state, municipal and county agencies. In addition, Rule 3627 provides that other stakeholders, including organizations and individuals representing various interests that have indicated a desire to participate in the planning process, must also have an opportunity for meaningful participation. Under Rule 3627, Public Service is 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, Public Service participates in numerous CCPG subcommittees, working groups and task forces, where it engages with interested stakeholders and responds to their comments. The following is a synopsis of the outreach that Public Service performed relevant to this rule. Also, Appendix K lists responses to comments received from stakeholders.

1. Rule 3627/FERC Order 890 Stakeholder Meetings

In order to comply with the public engagement requirements of both Rule 3627 and FERC Order 890, Public Service facilitates two open stakeholder meetings per year. The meetings are held in the first and fourth quarters each year at the Public Service's Denver office. Since the filing of the 2022 Ten-Year Transmission Plan, Public Service hosted formal FERC Order 890/Rule 3627 stakeholder engagement meetings on March 23, 2022, December 13, 2022, March 23, 2023, and December 19, 2023.

For the meeting on December 19, 2023, Public Service developed an informational PowerPoint presentation that included information on the long-range transmission plans developed pursuant to Rule 3627 and certain other matters addressed in FERC Order 890. Invitations were sent to 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 state and local governments, consumer interests, environmental interests, consulting firms, law firms, and other individuals and groups. Approximately 70 of the over 300 invitees attended the presentation. Since self-identification was optional, it was not possible to determine the identity of those who dialed in from a land line. After the presentation, Public Service gave stakeholders the opportunity to participate in and comment on the transmission plan put forth in this Report.

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

2. Project-Specific Public Outreach

Colorado's Power Pathway

Following approval by the Colorado Public Utilities Commission, Public Service began an aggressive plan to engage with property owners, community leaders, stakeholders and the public regarding Colorado's Power Pathway and its routing process. Since the middle of 2021, Public Service has conducted the following work to achieve this objective:

- Mailed more than 172,000 postcards
- Received more than 750,000 Facebook meeting notice ad views
- Received more than 40,000 unique website views
- Placed 164 newspaper ads in 35 local papers
- Received 1,275 general questions and comments
- Emailed more than 9,500 newsletters
- Conducted more than 80 meetings with agencies, cities and counties
- Conducted over 40 public meetings, welcoming nearly 3,000 attendees
- Placed 425 ads on 12 radio stations
- Receive 1,532 public comment forms

Public Service conducted significant outreach and communications activities in 2022 and 2023 to provide the public with routing updates and permit fling process information, present revised transmission line route options and substation locations and gather feedback. Public Service used direct mail, email, web, newspaper and radio advertising, social media and direct communications with landowners and the public to promote community meeting (open house) events. Project managers also met with county planning commissions and boards of county commissioners throughout the permitting process, notices for which came through sign postings along preferred routes and county communications channels. Following is a listing of all public events:

Winter 2022 community meetings:

- Jan. 24 – Platteville Community Center, Platteville, Colorado
- Jan. 25 – Fort Morgan Field House, Fort Morgan, Colorado
- Jan. 26 – Washington County Event Center, Akron, Colorado
- Jan. 27 – Grassroots Community Center, Joes, Colorado
- Jan. 27 – Community Center, Siebert, Colorado
- Jan. 31 – Pueblo Community College, Pueblo, Colorado
- Feb. 1 – The Heritage Center, Crowley, Colorado
- Feb. 1 – Kiowa County Fairgrounds, Eads, Colorado
- Feb. 2 – Cheyenne County Fairgrounds, Cheyenne, Colorado
- Feb. 2 – Lamar Community Building, Lamar, Colorado
- Feb. 3 – Baca County Resource Center, Springfield, Colorado
- Feb. 28 – Arapahoe County Fairgrounds Event Center, Aurora, Colorado

- March 1 – Elbert County Fairgrounds, Kiowa, Colorado
- March 2 – Big Sandy Schools, Kiowa, Colorado
- March 3 – Edison School District, Yoder, Colorado

Spring 2022 community meetings:

- May 2 – Arapahoe County Fairgrounds Event Center, Aurora, Colorado
- May 3 – Elbert County Fairgrounds, Kiowa, Colorado
- May 4 – Big Sandy Schools, Simla, Colorado
- May 5 – Edison School District, Yoder, Colorado

Summer 2022 community meetings:

- Aug. 3 – Limon Community Building, Limon, Colorado
- Aug. 4 – Karval Community Building, Karval, Colorado
- Aug. 9 – Kiowa County Courthouse, Eads, Colorado

Fall/Winter 2022 public hearings:

- Sept. 14 – Morgan County Board of County Commissioners
- Sept. 27 – Morgan County Board of County Commissioners
- Oct. 4 – Morgan County Board of County Commissioners
- Sept. 19 – Washington County Planning Commission
- Nov. 4 – Washington County Board of County Commissioners
- Sept. 29 – Cheyenne County Planning and Zoning Board
- Sept. 30 – Cheyenne County Board of County Commissioners
- Sept. 20 – Kit Carson County Planning Commission
- Sept. 21 – Kit Carson County Board of County Commissioners
- Nov. 21 – Washington County Planning Commission
- Dec. 13 – Washington County Board of County Commissioner

Fall 2023 community meetings:

- Oct. 10, 4-8 p.m. in Simla, Colorado
- Oct. 18, 4-8 p.m. in Kiowa, Colorado

In addition to community meetings, Public Service conducted a formal groundbreaking event in June 2023 with Company and project leaders, elected officials, key stakeholders and the news media to highlight the beginning of construction on Segments 2 and 3. The project website was also expanded to display an interactive digital map of the project in which the public may obtain detailed construction progress information.

Greenwood – Denver Terminal Transmission Rebuild/Upgrade

Public Service completed construction of on 15.4 miles of transmission facilities between the Greenwood Substation and the Denver Terminal Substation within existing rights-of-way. This project is an upgrade from the existing 115kV transmission line to a 230kV transmission line. The project was located in six different jurisdictional boundaries: Centennial, Greenwood Village, Littleton, Englewood, Sheridan and Denver.

Public Service produced and regularly updated a sophisticated project website for the project, providing the public with detailed information about the project, including photo simulations and an interactive map with construction progress updates. Additional outreach with property owners adjacent to the project included direct mail, email and personal contacts. Public Service conducted or participated in project open houses (virtual and in-person) and public hearings within the six jurisdictions prior to 2022, when construction began.

Ault-Cloverly 230/115 kV Transmission Project

The Ault-Cloverly 230/115 kV Transmission Project, also referred to as the Northern Colorado Area Plan ("NCAP"), 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. Public Service was granted a CPCN for this project in Proceeding No. 17A-0146E.

Since planning, siting and land rights work began on the NCAP project, Public Service's outreach and communications activities have included seven separate mass mailings to more than 7,000 addresses, 425 landowner meetings, five open house events and five community working group meetings that welcomed more than 330 attendees, 37 meetings with local officials and 177 briefings with community leaders. Public Service uses a special project website with an email and telephone hotline for public information and contacts, digital newsletters, community event participation and direct outreach to provide regular updates for stakeholders and the public. During 2022 and after construction began in 2023, Public Service participated in or hosted the following public meetings and hearings:

- Jan. 5, 2022 Weld County Board of County Commissioners hearing
- March 3, 2022 Town of Eaton Planning Commission Hearing
- March 17, 2022 Town of Eaton Board of Trustees Hearing
- Sept. 13, 2023 Public Open House in Eaton

Poder Substation[19]

Beginning in 2022, Public Service began outreach and communications with the northern Denver communities of Elyria-Swansea, Globeville, Five Points and other neighborhoods surrounding the National Western Center. Public Service developed a project website, email address and hotline phone number to provide information, take comments and respond to inquiries. Prior to the formal open house, Public Service attended several community events to hand out information and answer questions.

- Sept. 9, 2022 – Focus Points Family Resource Center Meeting
- May 6, 2023 – Swansea Elementary School's Spring Festival
- Aug. 5, 2023 – Swansea Elementary School's Back to School Night
- Sept 7, 2023 – Swansea Elementary School's Open House
- Oct. 11, 2023 – Open House at Swansea Recreation Center

[19] This project has been previously identified in Public Service's reporting as the Stock Show Substation.

To promote the open house, Public Service mailed postcards; handed out flyers to Swansea Elementary families; distributed flyers throughout the neighborhood; updated its website; and updated the project information telephone line.

Castle Rock (WFRZ) Transmission Rebuild

Public Service is currently in the process of rebuilding-in-place approximately 25 miles of 115 kV transmission lines connecting the Palmer Lake, Castle Rock, Crowfoot Valley, Happy Canyon and Daniels Park substations in Douglas County. The transmission lines, located within a wildfire risk zone, were originally built in the 1950s and have reached the end of their useful lives.

Prior to beginning construction on the first segment, from the Palmer Lake to Castle Rock substations, Public Service conducted a mass mailing to property owners abutting the line's right-of-way to inform them of the project and to provide information about it. Public Service stood up a project website with project background information and an email and hotline for direct engagement with the public and directly engaged with property owners concerning easement access and construction activities.

Alamosa to Antonito Transmission Rebuild

The Alamosa to Antonito Transmission Line Rebuild Project, announced in November 2021, involves rebuilding approximately 39 miles of 69 kV electric transmission line between the Alamosa Terminal and Antonito substations to modern standards. Throughout the process, Public Service conducted eight open house events, each promoted by a direct mailing to more than 4,000 addresses, email notifications, project website updates and newspaper advertisements. During 2022 and 2023, Public Service hosted the following open house events to which a total of approximately 140 people attended:

- March 7, 2022 (Virtual/Zoom)
- March 9, 2022 in Alamosa, Colo.
- March 10, 2022 in La Jara, Colo.
- July 31, 2023 (Virtual/Zoom)

- Aug. 2, 2023 in Alamosa, Colo.
- Aug. 3, 2023 in La Jara, Colo.

Public Service also has conducted dozens of personal meetings with individual landowners and regularly updates the project website with information about the project and its progress.

Glenwood-Mitchell Creek Transmission Rebuild

Public Service resumed meetings with Glenwood Springs city staff and management concerning the Glenwood to Mitchell Creek Transmission Line Rebuild project. This project consists of rebuilding approximately two miles of 69kV transmission line located within a wildfire mitigation zone to modern standards. Public Service engaged with the city about the project during the following:

- Dec. 6, 2023 public open house
- Dec. 12, 2023 Glenwood Springs Planning Commission Hearing

Public Service established and regularly updates a special project website that provides background on the project and scheduled activities. Project communications also includes direct mail, email and contact with local news media.

Malta to Otero Transmission Rebuild

As part of its wildfire mitigation program, Public Service will replace the 50-year-old transmission line that runs from the Malta substation southward to the Otero tap, roughly adjacent to US-24 between Lake County Road 52 and Chaffee County Road 371. Public Service has conducted outreach with all property owners along this circuit, through direct mail and personal contacts, engaging with each concerning easements and project information. A project website, with email and hotline, was developed to provide the public with information and scheduled activities, and direct communications with key stakeholders continues. On June 14, 2023, Public Service participated in a public hearing with the Chaffee County Board of Commissioners to present the project and answer questions pertaining to its permit filing.

Kestrel Substation

Public Service will extend an existing 230 kV electric transmission line and construct a substation to connect and serve a new customer in the City of Aurora, in both Adams and Arapahoe counties. Public Service has conducted outreach with all property owners along this circuit, through direct mail and personal contacts, engaging with each concerning easements and project information. A project website was developed to provide the public with information and scheduled activities. On Oct. 25, 2023, Public Service hosted an open house in Aurora, Colorado to present the project and answer questions pertaining to its permit filing.

Pintail Interconnection

Public Service will build a new 115 kV electric transmission line on steel monopoles from the existing Anadarko Substation to connect and supply the power to operate the proposed Phillips 66 Pintail Compressor Station, approximately 2.5 miles east of the Town of Gilcrest in Weld County, Colorado. Public Service developed a project website, with email and telephone hotline, to provide the public with project information and a schedule of activities associated with it. In late June 2023 Public Service participated in an open house hosted by Phillips 66 to discuss the compressor station project. On July 11, 2023 Public Service hosted an open house in Platteville, Colorado to inform the public about the interconnection project and to answer questions about it. Both open houses were promoted by direct mailings to surrounding property owners and by direct communications with stakeholders and local officials.

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 Western Slope Subcommittee

The CCPG Western Slope Subcommittee provides an avenue to discuss and perform analysis on changes to the Western Slope transmission system in the near-term (years 1-5) and long-term (years 6-10) planning horizons. Proposed studies focus on, though are not limited to, emerging technical considerations, public policy changes, and/or announced utility company decisions that could have a direct impact on the performance of the Western Slope transmission system and associated WECC Paths. The resultant study and report, while not definitive, should provide insight and guidance on how these changes affect the transmission system and may be used to guide more targeted subsequent study efforts.

The following studies were performed this year.

1. Impact of increasing transfer capacity between CCPG and the Western Market.
    a. This is a continuation of a study included in the 'Western Slope 2022 Study Report' to access possible transmission projects meant to increase transfer capacity between CCPG and the larger Western Market. Two projects will be studied: (1) a 500 kV AC line between Craig substation and PacifiCorp's Gateway South 500 kV transmission line, and (2) a 500 kV DC line between Craig and San Juan substations.
2. Evaluation of a multi-purpose 345 kV line between Montrose and Tundra substation
    a. This study scenario involves the addition of an approximately 200-mile long 345 kV line between Montrose and Tundra substations. The study will evaluate the impact of the proposed line on TOT 5 in both the prevailing west to east and non-prevailing east to west directions. This project includes a potential connection at Poncha substation to evaluate the impacts of San Luis Valley solar exports (up to 1,000 MW) on the project and surrounding system.
3. Evaluation of "upgrading" the existing Western Slope transmission system.
    a. This study will look at leveraging the existing transmission system by 'upgrading' it to the transmission line design standard used by each Transmission Owner today. Considerations for this study include:
        i. "Upgrade" of "underbuilt" 115kV and/or 138kV transmission lines (e.g., upgrading 80 MVA lines to 174+ MVA).
        ii. Conversion of existing lines that were built to one voltage level but operated at a lower voltage level.

iii. Craig – Rifle (WAPA) 230 kV, built for 345 kV.

iv. Montrose – Maverick – Cahone 115 kV, built for 230 kV.

b. Creation of designated “open points” to prevent thru flows in the 115 kV and 138 kV transmission system for outages that occur in the 345 kV and 230 kV system.

The following stakeholders participated in the CCPG Western Slope Subcommittee:

- Dietze & Davis, on behalf of Independent Power Producers
- Interwest Energy Alliance
- Office of Consumer Council
- Public Service Company of Colorado
- Staff of the Colorado Public Utilities Commission
- Tri-State Generation & Transmission Association
- Western Area Power Administration
- Western Resource Advocates

Meetings were held on:

- October 8, 2020
- December 17, 2020
- January 13, 2022
- April 21, 2022
- July 28, 2022
- November 17, 2022
- January 17, 2022

F. CCPG San Luis Valley Subcommittee

The SLV was formed on September 15, 2015, to serve as the transmission planning forum to develop the study process and identify the transmission alternatives that most effectively address the SLV transmission system limitation adequately. The objectives to address are improved reliability, increased load serving capability, increased generation export capability and to allow for improvements to aging infrastructure. While earlier transmission studies were produced in 2016 and 2017, a new refreshed study is currently underway. This study is broken into two phases, with Phase I focused on alternatives which mitigates the existing reliability issues and increase load serving capabilities while Phase 2 focuses on alternatives that increase the transfer capability and increased generation export from the valley to the Front Range load centers.

The following stakeholders participated in the San Luis Valley Subcommittee:

- Black Hills Energy
- BayWa r.e.
- Colorado Solar and Storage Association
- Colorado Springs Utilities
- CTG Global
- Dietze & Davis, on behalf of Independent Power Producers
- Interwest Energy Alliance
- Platte River Power Authority
- Public Service Company of Colorado
- Staff of Alamosa County
- Staff of the Colorado Office of Utility Consumer Advocate
- Staff of the Colorado Public Utilities Commission
- Staff of US Senator Bennet
- Tri-State Generation & Transmission Association
- Western Area Power Administration
- Western Resource Advocates

Meetings were held on:

- May 18, 2022
- July 21, 2022
- October 20, 2022
- February 2, 2023

- June 14, 2023
- July 6, 2023

Eight alternatives were studied in Phase I, each with the goal of transporting power to Poncha or serving load in the San Luis Valley. The eight alternatives were:

- Alternative 1:
  - Rebuild SLV-Poncha 69 kV to 115 kV
    - Sensitivity with Carbon Core Conductor
- Alternative 2:
  - Rebuild SLV-Poncha 69 kV to 230 kV
    - Sensitivity with Carbon Core Conductor
- Alternative 3:
  - Rebuild SLV-Poncha 115 kV to 230 kV
    - Sensitivity with Carbon Core Conductor
- Alternative 4:
  - New SLV-Poncha 230 kV
    - Sensitivity with Carbon Core Conductor
- Alternative 5:
  - New double circuit SLV-Poncha 345 kV
    - Sensitivity with Carbon Core Conductor
- Alternative 6:
  - Battery Storage
- Alternative 7:
  - Reconductor SLV-Poncha 115 kV with carbon core
- Alternative 8
  - SLV-New Sub 230 kV
    - Route following CO114 to new sub along Curecanti-Poncha 230 kV
    - Sensitivity with Carbon Core Conductor

Phase 2 focuses on alternatives that increase transfer capability and generation export from the valley to the Front Range. The ten alternatives are:

- Alternative 1:
    - Use ATT (flow control) on Poncha-Midway
- Alternative 2:
    - New Poncha-Midway 230 kV
        - Sensitivity with Carbon Core Conductor
- Alternative 3:
    - New Poncha-Malta 230 kV
        - Sensitivity with Carbon Core Conductor
- Alternative 4:
    - Reconductor existing Poncha-Malta 115 kV line with carbon core
- Alternative 5:
    - Poncha-Tundra 345 kV Double Circuit
        - Sensitivity with Carbon Core Conductor
- Alternative 6:
    - Poncha-Midway + Poncha-Tundra 345 kV
        - Sensitivity with Carbon Core Conductor
- Alternative 7:
    - New Poncha-Midway-Tundra DC Line
- Alternative 8
    - New Sub-Poncha-Midway 230 kV
        - Corresponds to Phase 1, alternative 8
        - Sensitivity with Carbon Core Conductor
- Alternative 9
    - Reconductor existing Poncha-Midway and SLV-Poncha with Carbon Core Conductor
- Alternative 10
    - Uprate SLV-Poncha 230 kV + RAS
        - Remove terminal limits
        - With carbon core conductor

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

The ESWG focused on creating an Evaluation Guide for transmission planners to use during project planning to consider alternatives to traditional transmission assets, including energy storage resources and NWAs. Since the last Ten-Year Transmission Plan was filed pursuant to Commission Rule 3627, the ESWG met four times to receive feedback and comments from stakeholders and CCPG members and to thoroughly deliberate and draft the Evaluation Guide. On June 22nd, 2023, the ESWG accepted the draft of "A Guide to Evaluating Energy Storage Alternatives" along with an Evaluation Matrix as a companion document to record the evaluation process as a transmission project is studied. The ESWG's publications were presented without objection during the June 29, 2023 CCPG meeting. The Evaluation Guide and Matrix are available for download at: https://doc.westconnect.com/Documents.aspx?NID=21025%20.

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 the "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
- Siting and land rights
- Impacts on local communities and tribal nations
- 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 F.

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; and,
- 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; and,
- 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 proceedings and initiatives, spending significant time and resources for Notices of Proposed Rulemaking, recurring transmission proceedings (*i.e.* Rule 3206 proceedings and CPCN proceedings), 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 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 that relate 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 Transmission Planning ("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 in 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 2024 Plan complies with all applicable NERC and WECC reliability standards and other applicable legal and regulatory requirements. These requirements are the 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. 22A-0230E. Resource planning covers a Resource Acquisition Period of nine years from January 2022 through December 2030. RES compliance covers a period of 2023 through 2026. 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 included the acquisition of 100 MW of wind, 200-250 MW of solar and 50 MW of storage through a competitive solicitation. A request for proposals was released on July 31, 2023, and bids were submitted on October 20, 2023. On December 19, 2023, bidder notifications (indicating which bids are advancing to computer modeling) were issued. The Company will issue its 120-day report indicating its preferred portfolio and other portfolios by April 17, 2024. While the Phase II process is not yet complete, it is likely that the outcome of the CEP will have future implications and the need for interconnections to the Black Hills transmission system.

2. Tri-State Legal Requirements

Tri-State's 2024 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. 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 2024 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.

In January 2022, Tri-State reached a comprehensive settlement agreement related to Phase I of its 2020 Electric Resource Plan that includes binding emissions reduction targets for Tri-State's wholesale electricity sales in Colorado, including an 80% reduction of GHG emissions below 2005 levels by 2030. These targets also will be included in Tri-State's 2023 Electric Resource Plan filing.

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 any future 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

Consistent with Rule 3627(b)(III), Public Service's 2024 Plan is consistent with its currently operative ERP, approved by the Commission in Proceeding 16A-0396E in its Phase II decision, C18-0761.[20] Public Service's 2021 Clean Energy Plan & Electric Resource Plan is pending before the 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.

Also consistent with Rule 3627(b)(III), Public Service's 2024 Plan is consistent with its currently operative Renewable Energy Standard Compliance Plan ("RE Compliance Plan") approved by the Commission in Proceeding No. 21A-0625EG.

Information on Public Service's RE Plan and programming 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.

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

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 2024 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 filing) of Attachment K is located in Appendix O.

3. Public Service Participation Strategy

Public Service's participation process is governed by its FERC Order No. 890 stakeholder process, which is included in Attachment R of the current Xcel Energy Operating Companies Joint OATT Attachment, which is available at: https://www.transmission.xcelenergy.com/staticfiles/microsites/Transmission/Files/PDF/Xcel%20Energy%20OATT%20Current%20Tariff.pdf. Additional information concerning the Public Service's Rule 3627 and FERC Order No. 890 stakeholder engagement processes can be found at http://www.oatioasis.com/psco/index.html under "FERC 890/PUC Rule 3627 Postings."

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

In July 2011, FERC issued the 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"[21] 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

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

project, then those Colorado utilities may be responsible for a portion of the cost of the regional project.

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

F. Powerline Trails

In 2022, the Colorado Legislature adopted in HB22-1104, the Powerline Trails Act. The Powerline Trails Act is intended to encourage the development of multimodal recreational trails in electric transmission line corridors within Colorado by directing transmission providers to disclose certain information for powerline trail development and by enabling contracts for the construction and maintenance of such trails. The Commission adopted rules implementing reporting requirements associated with the Powerline Trails Act in Ten-Year Transmission Plans in Proceeding No. 23R-0069E.

1. Tri-State Powerline Trail Compliance

The following Tri-State projects have the potential for the construction of a powerline trail:

Table 14.

Transmission Line Project	**Project Location (County)**
Big Sandy – Badger Creek 230 kV	Adams, Arapahoe, Elbert, Morgan, Lincoln, Washington
Big Sandy – Burlington 230 kV	Lincoln, Kit Carson
Boone – Huckleberry 230 kV	Pueblo
Burlington – Lamar 230 kV	Prowers, Kiowa, Cheyenne, Kit Carson
Lost Canyon – Main Switch 115 kV	Montezuma
Poncha – San Luis Valley 230 kV	Alamosa, Chaffee, Saguache
Slater Double Circuit Conversion	Boulder, Weld

Note: It is assumed that the above projects could traverse the identified counties. Not all projects listed above have a defined route as they are conceptual or in various stages of the planning, or permitting, etc. process at this time.

Powerline trails are actively being considered, planned, or developed by Tri-State for the following projects:

- Tri-State is not actively considering, planning, or developing any powerline trails at this time.

Tri-State's powerline trail information required pursuant to § 33-45-103(2)(a), C.R.S. may be found at https://tristate.coop/operations.

2. Public Service Powerline Trail Compliance

When Public Service seeks to site a new transmission line or expand an existing transmission line within a local jurisdiction, Public Service will (1) notify local governments of the potential for construction of a powerline trail within the transmission corridor; and (2) help inform the public entities of the guidelines for which a trail can safely co-locate within the transmission corridor. Powerline trails may ultimately be constructed by public entities after consulting with Xcel Energy, the Colorado Division of Parks and Wildlife, and landowners about the safety and feasibility of such trails, and after the transmission corridor is constructed. To co-locate a public recreation trail within Public Service's transmission corridor, the public entity must follow Public Service's Encroachment Guidelines and safe practices around power lines. Public Service's powerline trail information provided pursuant to § 33-45-103(2)(a) may be found at: https://www.transmission.xcelenergy.com/right-of-way.

Pursuant to the requirements of Commission Rule 3627(c)(X), Public Service provides the following list of planned transmission line projects that site a new transmission line, extend an existing transmission line by more than one mile, or increase the capacity of an existing transmission line by more than ten percent (as measured by an increase in the thermal rating of the conductor used for the transmission line). Some of these projects are maintenance-driven projects that do not ordinarily fall within the scope of Commission Rule 3627 and are not otherwise discussed within this Ten-Year Transmission Plan. Public Service has not made any determination of the extent to which any of these projects may be suitable for powerline trail development and is not currently actively considering, planning, or developing powerline trails associated with any transmission line project in Colorado.

Table 15.

Transmission Line Project	Project Location (County)
Colorado's Power Pathway	Weld, Morgan, Washington, Kit Carson, Cheyenne, Kiowa, Crowley, Pueblo, El Paso, Lincoln, Elbert, Arapahoe
Leadville to Climax Line Rebuild	Lake, Eagle
Avon – Gilman 115 kV Transmission	Eagle
Ault – Cloverly 230/115 kV Transmission	Weld
De Beque to Rifle Line Rebuild	Mesa, Garfield
Rifle to Glenwood Springs Line Rebuild	Garfield
Poncha to San Luis Valley 115 kV Line Rebuild	Rio Grande, Saguache, Chaffee, Alamosa
Kestrel Substation and Transmission Line	Adams
Alamosa to Antonito Line Rebuild	Alamosa, Conejos
Alamosa to Sargent Line Rebuild	Alamosa, Rio Grande
Hopkins to Basalt Line Rebuild	Garfield, Eagle
Malta to Otero Line Rebuild	Lake, Chaffee
Castle Rock to Palmer Lake Line Rebuild	Douglas
Boulder Hydro to Boulder Line Rebuild	Boulder
Mirage Junction to Saguache Line Rebuild	Saguache
Daniels Park to Castle Rock Line Rebuild	Douglas
Uintah to Fruita Line Rebuild	Mesa

Public Service provides notice to local jurisdictions as required by the Powerline Trails Act as part of the local permitting pre-application notice required by § 29-20-108(4)(a), C.R.S., including an information sheet about the Powerline Trails Act and a link to Public Service's website noted above. Public Service will provide notice to local jurisdictions for all projects that fall under the requirements of the Powerline Trails Act, and has made notifications to the following local jurisdictions about the potential for powerline trail development associated with transmission line projects:

Table 16.

Transmission Line Project	Jurisdiction	Date of Notification
Colorado's Power Pathway	Pueblo County	11/2/2023
	Crowley County	12/27/2022
	Arapahoe County	5/16/2023
	City of Aurora	5/16/2023
	El Paso County	8/11/2023
	Elbert County	7/11/2023
	Lincoln County	5/15/2023
DeBeque to Rifle Rebuild	Town of Parachute	10/9/2023
	City of Rifle	10/10/2023
Rifle to Glenwood Springs Rebuild	Town of New Castle	8/30/2023
	City of Glenwood Springs	11/10/2023
Poncha to San Luis Valley 115 kV Rebuild	Chaffee County	8/28/2023
Kestrel Substation and Transmission Line	Adams County	5/31/2023
	City of Aurora	4/19/2023

VIII. 10-Year Transmission Plan Supporting Documentation

A. Background Context Concerning Models and Model Outputs

As a foundational matter, it is critical to understand the role that transmission models play within the transmission planning process. Unlike resource planning, in which modeling software is used to develop an optimized portfolio of generators that meet cost, emissions, and reliability objectives from a variety of potential solutions, transmission planning models serve a different function. Planning models are used by transmission planning engineers to evaluate the impact of future generation and load on the existing bulk power system so that system needs can be identified. Once these needs are identified, planning engineers must exercise their professional judgement to devise a series of alternatives that may be capable of addressing the identified need. Traditionally, these alternatives have primarily focused on upgrading the capacity of existing transmission facilities or creating new transmission links between points on the transmission system, but today other technological alternatives such as energy storage are considered through this process as well. Transmission planning models are then used to test the efficacy and electrical characteristics of the alternatives that the transmission planning engineer developed for analysis, which is used in combination with other information (such as the feasibility or relative cost of alternatives) for the selection of a preferred alternative.

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.[22] In the interests of transparency and addressing this issue from the outset, the Joint Utilities reiterate that while they can provide instructions for accessing modeling information, they cannot directly 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 executed. 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.

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 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

[22] *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.")

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, but 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 can be 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.

a. 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.

b. Public Service Ratings

Documentation of Public Service FAC-008-005 methodology can be found in Appendix P. Public Service will implement the line rating methodology requirements of FERC Order No. 881 consistent with Attachment S to the Xcel Energy Operating Companies Joint OATT, effective July 12, 2025.

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

The Companies utilize transmission system power flow and transient stability modeling data prepared by 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 2023, Black Hills filed with the Commission its latest ERP (Proceeding No. 22a-0230E), 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' 2023 ERP in Colo. Consolidated Proceeding No. 22A-0230E; specifically, Attachment LS-1, which is 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 2022 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

Table 17. Tri-State Summer 2022 Demand Forecast (MW)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Annual Energy Sales (GWh)	16,331	15,265	14,777	14,923	15,154	15,398	15,627	15,839	16,080	16,331
Summer Peak Demand (MW)	3,330	3,145	3,138	3,154	3,195	3,324	3,361	3,404	3,445	3,491

c. Public Service Forecasts

The load forecast referenced by this filing is Public Service's Fall 2022 load forecast, as filed with the Commission on March 31, 2023 in the ERP Annual Progress Report in Proceeding No. 21A-0141E. Table 18 below shows the Public Service load forecast.

Table 18. Public Service Company Fall 2022 Demand Forecast (MW)

		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
1	Res Base Forecast	3,263	3,264	3,272	3,282	3,300	3,329	3,360	3,389	3,418	3,451	+
2	Non-Res Base Forecast	3,362	3,422	3,455	3,499	3,519	3,547	3,566	3,595	3,623	3,675	+
3	DSM Forecast	18	29	27	16	(4)	(29)	(59)	(92)	(129)	(166)	-
4	BE Forecast	-	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.2	+
5	EV's Forecast	14	27	40	52	67	86	110	140	174	210	+
6	IVVO Forecast	29	28	35	34	34	33	33	32	32	31	-
7	Oil&Gas Forecast	-	-	-	-	-	-	-	-	-	-	+
8	Solar Forecast	227	261	299	335	366	395	425	458	487	512	-
9	**Retail Forecast**	**6,365**	**6,395**	**6,407**	**6,448**	**6,491**	**6,562**	**6,636**	**6,726**	**6,826**	**6,958**	*9 = 1 + 2 - 3 + 4 + 5 - 6 + 7 - 8*
10	Wholesale Forecast	515	502	518	177	181	179	187	191	191	192	+
11	**Obligation Forecast**	**6,880**	**6,897**	**6,925**	**6,625**	**6,673**	**6,742**	**6,823**	**6,918**	**7,017**	**7,149**	*11 = 9 + 10*
12	Solar Forecast	227	261	299	335	366	395	425	458	487	512	+
13	Conversion Adjustments	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	+
14	**PSCo Native Load Forecast – Fall2022 (MW)**	**7,107**	**7,157**	**7,224**	**6,960**	**7,037**	**7,136**	**7,247**	**7,374**	**7,502**	**7,659**	*14 = 11 + 12 + 13*

Public Service's forecast native peak demand (retail and firm wholesale requirements) is expected to grow at a compounded annual rate of approximately 0.75 percent between 2024 and 2032. The Company's forecasts show retail load growing by a compounded annual rate of approximately 0.95 percent, which is offset by declining wholesale load driven primarily by the expiration of wholesale generation contracts.

Public Service has seen a rise in both formal load requests and informal inquiries about transmission capacity through its development group. Public Service sees potential for substantial growth in redevelopment and expansion projects, including large-scale commercial and residential developments, as well as data centers in the Denver metro area. This expansion would require additional substations to deliver energy to customers, and meeting this added load could involve upgrades to the transmission network to match the growing demand. The considerable rise in load within key hotspots throughout Denver and surrounding areas could have a material impact on Public Service's long-term plan for these areas. Public Service will continue to assess and analyze customer requests but does not account for these loads and associated transmission network upgrades in the Ten-Year Transmission Plan given their speculative nature at this time.

Public Service's load forecast assumes an increase in adoption of electric vehicles ("EVs") through the forecast period. By 2030, Public Service expects about 440,000 EVs in its service territory. The CEO estimates that there are currently over 78,000 battery electric vehicles and over 30,000 plug-in hybrid electric vehicles on the road throughout the State of Colorado. EVs constitute 210 megawatts ("MW") of the base peak forecast in 2032 – the EV MWs included in the forecast are included in line 5 above.

The forecasts are adjusted for Public Service's Demand Side Management ("DSM") programs and the expected savings from the Integrated Volt/Var Optimization capabilities of advanced meters. The MW adjustments to the forecast are included in lines 3 and 6 above. The demand forecast reflects native load and therefore excludes the impact of Distributed Energy Resources ("DER"). However, the DER are included in the solar forecasts in line 12 above.

In addition to Public Service's native load forecast, Public Service receives load forecast from its network customers, which it incorporates into the overall Public Service network load forecast. The forecasted Public Service network load is then allocated on a substation-by-substation basis to load buses in the transmission planning model, based on historical trends.

Consistent with the Commission's directives in Decision No. C22-0319-I, Public Service provides the following supporting information related to its 2034 load forecasts. Public Service notes that these data points are not necessarily applicable to or used as part of the Transmission Planning process or the analysis used to develop the Ten-Year Transmission Plan:

- Summer Peak Load is generally considered when evaluating projects where the local system is a summer peaking system or system-wide capacity planning projects, typically those driven by public policy goals; however, the summer peak load data provided in this table may not align with the planning assumptions used to model specific projects identified in Public Service's Ten-Year Transmission Plan. The Summer Peak Load data used in the analysis of projects identified in Public Service's Ten-Year Transmission Plan is listed in Table 8, where applicable.

- Winter Peak Load may be considered when evaluating projects where the local system is a winter peaking system. For the purposes of capacity planning, Public Service's electric system is a summer peaking system.
- Reduced peak load when renewable generation is maximized is not generally considered in the transmission planning process.

Table 19.

2034 Summer Peak – Native Load (MW)	2034 Winter Peak – Native Load (MW)	2034 Reduced summer peak load when BTM generation is maximized (MW)	2034 Reduced winter peak load when BTM generation is maximized (MW)
7,159	6,160	6,893	6,160[23]

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 2023 Black Hills ERP; specifically, Attachment LS-1, which is included in Appendix N of this document.

[23] Public Service's forecasted 2034 winter peak hour occurs during a time in which there is no forecasted BTM generation.

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 2023 ERP.

c. Public Service DSM

Public Service accounts for DSM, including demand response initiatives, through reduction in its load forecast based, in part, on the goals established by the Commission. Information concerning Public Service's DSM forecasts are referenced in Section VIII.C.1.c. above. Public Service's 2024-2026 DSM and BE Plan is currently pending before the Commission in Proceeding No. 23A- 0589EG. Public Service's 2023 DSM and BE Plan was approved by the Commission in Proceeding No. 22A-0315EG.

D. Generation and Dispatch Assumptions

Generator and associated equipment models are typically included in the WECC Annual Base Case[24] 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

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

performance of individual wind turbines is not a concern. The scope of the technical study will influence the level of detail that is modeled.

1. Black Hills Assumptions

At the most basic level, Black Hills dispatches existing generation to meet the demand requirements of its system, including load and losses. The objective of a particular study often drives the individual generator dispatch levels. For example, a peak demand summer baseline scenario may consist of a majority of dispatchable baseload generation online and an appropriate mix of wind and solar PV to meet the demand requirements. An off-peak demand spring or fall scenario may have the available wind generation dispatched at its nameplate capacity with the dispatchable baseload generation and solar generation reduced to capture the impacts of that particular dispatch pattern. Existing power purchase agreements and other contractual arrangements may be reflected in certain study scenarios to further stress the transmission system. Black Hills also may include speculative generation (as identified in the current version of the Black Hills Colorado Electric Generation Interconnection Request Queue, included in Appendix 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

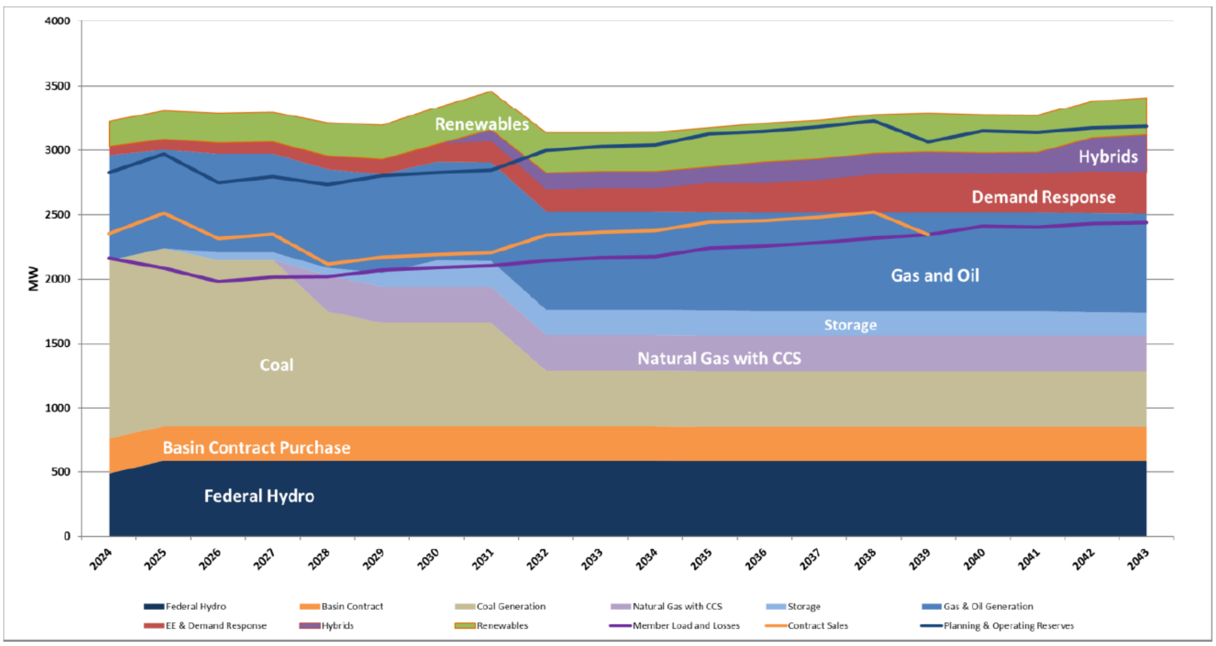
Tri-State's transmission planning function receives generation assumptions from its network customers – Tri-State Power Management, Arkansas River Power Authority ("ARPA"), Municipal Electric Agency of Nebraska ("MEAN"), Raton Public Service Company ("City of Raton"), Public Service, Kit Carson Electric 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.

Table 2: Load & Resources (L&R), IRA Scenario

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Resources (MW)	3225	3303	3286	3291	3210	3193	3332	3458	3134	3134
Total Obligations (MW)[12]	2826	2970	2750	2794	2733	2801	2827	2846	2997	3027
Excess (MW)	398	333	536	498	477	392	504	612	137	107

Figure 2: Load & Resources (L&R), IRA Scenario



Nevertheless, Tri-State is providing a table of the annual expected capacity for each existing and planned resource in its generating portfolio (inclusive of power purchase agreements) for 2024 through 2034 in Appendix O. Tri-State is also providing the Load and Resources table associated with Tri-State's preferred IRA Scenario in its 2023 Phase I ERP below.[25]

[25] This table, as well as supporting information, can be found on Page 9 of Attachment LKT-1 to the Direct Testimony of Lisa Tiffin in Proceeding No. 23A-0585E.

3. Public Service Generation and 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 Public Service's OASIS website under External BPM for Large Generator Interconnection Procedures.

- Renewable generation, such as wind or wind plus battery storage hybrid generation facilities are dispatched at approximately 80 percent of nameplate rating. The solar or solar plus battery storage hybrid generation facilities are dispatched at approximately 85 percent of nameplate rating. Standalone battery storage facilities are modeled at approximately 90 percent of nameplate rating.
- Gas-fired combustion turbine generators are typically dispatched at approximately 90 percent 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 (approximately 100 percent 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 storage hydro generators are dispatched appropriately – in generating mode during peak and off-peak load hours and in pumping mode during light load hours.

Pursuant to the Commission's interpretive guidance concerning the reporting of generation assumptions in Paragraph 30 of Decision No. R22-0690, Public Service provides a table of the annual expected capacity for each existing and planned resource in its generating portfolio (inclusive of power purchase agreements) for 2024 through 2034 in Appendix P. Consistent with the Commission's directives in Decision No. C22-0319-I, Public Service provides the following supporting information concerning its 2034 generation forecasts. Public Service provides this data for informational purposes only and notes that this data is not applicable to or used as part of the Transmission Planning process or the analysis used to develop the Ten-Year Transmission Plan. Expected summer and winter peak coincident generation mix information is provided at a system level consistent with the values developed in Portfolio SCC10-USA in Phase I of Public Service's 2021 ERP & CEP pending before the Commission in Proceeding No. 21A-0141E. The expected cost of electricity is sourced from Portfolio SCC10-USA and represents wholesale energy costs only with all delivery costs excluded. Public Service expects that the values identified in this table will change based on the selection of a Phase II resource portfolio in the 2021 ERP & CEP but provides Phase I data in this Ten-Year Plan based on the timing the Commission's Phase II decision.

Table 20. 2034 Public Service Forecasted Electric Resource Planning System Data

Expected summer peak coincident generation mix	Expected winter peak coincident generation mix	Expected Cost of Electricity (2024$/MWh)
65% natural gas 11% wind 16% utility-scale and BTM solar 8% storage	79% natural gas 12% wind 9% storage % utility-scale and BTM solar[26] 9% storage	$134.32

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.

[26] There is no solar generation coincident with Public Service's 2034 winter peak that winter peak hour occurs after sunset.

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 website, 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 website, 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 website, 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 2024 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 2022 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 are performed by WestConnect. Western Interconnection-wide economic studies are 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.

IX. 2024 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