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, 2026

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ACRONYMS AND ABBREVIATIONS

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 2026 10-Year Transmission Plan for the State of Colorado ("2026 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 2026 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 2026 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 2026 Plan and the individual transmission projects included in the 2026 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 2026 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 2026 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 2026 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 2026 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. A larger map 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 2026 Plan [1]

Map and Project No.	Project Name	In-Svc	Cost ($ millions)	BH	TS	PS	Other	Purpose
1	Flying Horse Flow Mitigation	2024	$12.40			√	CSU	R
2	Fuller Transformer	2024	$14.60				CSU	L
3	Horizon Substation	2024	$47.40				CSU	L
4	Kettle Creek Transformer	2024	$2.80				CSU	L
5	Northern Colorado Area Plan (formerly Ault-Cloverly 230/115 kV Transmission) Project	2024	$123.50			√		L,R
6	Pike Solar	2024	$6.70				CSU	G
7	Fuller BESS	2025	$13.00				CSU	G
8	Metro Water Recovery Substation (100% customer funded)	2025	$16.00			√		L
9	Black Hollow Sun (BHS) Project	2026	$20.00				PRPA	G

[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.

Table 1: Transmission Projects included in the 2026 Plan [1]

Map and Project No.	Project Name	In-Svc	Cost ($ millions)	BH	TS	PS	Other	Purpose
10	Boone – Huckleberry 230 kV Line	2026	$40.60		√			G,L,R
11	Claremont Transformer	2026	$15.80				CSU	L
12	Horizon Transformer	2026	$15.80				CSU	L
13	Iron Mountain 115 kV Delivery Point	2026	$14.80		√			L
14	Kestrel (formerly Project Bronco) Distribution Substation (100% customer funded)	2026	$28.10			√		L
15	Montrose 115 kV Interconnect	2026	$3.70		√			G
16	Nixon-Kelker 230kV Line Uprate	2026	$0.20				CSU	R
17	Poder (Formerly Stock Show) Distribution Substation	2026	$5.90			√		L
18	Slater Double Circuit Conversion	2026	$7.60		√			L,R
19	Weld Battery Energy Storage System	2026	$3.60				PRPA	R
20	West Station to Portland 115 kV Rebuild	2026		√				R
21	Barker Distribution Substation	2027	$100.30			√		L
22	Central System Improvements	2027	$134.00				CSU	R
23	Cross Point 230/69kV Delivery Point	2027	$22.70		√			L,R
24	Daniels Park to Greenwood (Double) Circuit 5707 & 5111 Uprate	2027	$19.70			√		R
25	Hyde Park 115/13.2 kV Trsnsformer Addition	2027	$4.00	√				L,R
26	Leetsdale – Elati 230 kV Circuit 5283 Underground Transmission Line Upgrade	2027	$218.80			√		R
27	Rolling Meadows 115 kV Delivery Point	2027	$10.40		√			L
28	Sulfur Creek 138 kV Delivery Point	2027	$6.40		√			L
29	Sand Creek Switchyard	2027	$10.00				WAPA	R
30	Arapahoe 115 kV Bus Upgrades *(Duplicate with No.*	N/A	N/A			√		R

Table 1: Transmission Projects included in the 2026 Plan [1]

Map and Project No.	Project Name	In-Svc	Cost ($ millions)	BH	TS	PS	Other	Purpose
	58, entry exists/remains for clarity)							
31	Big Sandy – Badger Creek 230 kV Line	2028	$78.50		√			G,L,R
32	Big Sandy – Burlington 230 kV Line Uprate	2028	$13.90		√			G, R
33	Eastern Colorado Energy Center Interconnect	2028	$16.50		√			G
34	Greenwood Substation Upgrade	2028	$1.20			√		R
35	Rawhide Bus Expansion and Aeroderivative Turbine	2028	$21.00				PRPA	G
36	South System Improvements	2028	$71.00				CSU	L,R
37	Weld Transformer Replacement	2028	$9.00				WAPA	R
38	115 kV Pueblo Plant Substation Rebuild	2029	$6.50	√				R
39	Avon-Gilman 115 kV Transmission	2029	TBD			√		R
40	Blue Mesa Reactor and Transformer	2029	$9.80				WAPA	R
41	Cherokee to Broomfield 115 kV Circuits 9055/9558/9464 Uprate	2029	$58.20			√		R
42	Daniels Park Fourth Transformer *(Duplicate with No. 61, entry exists/remains for clarity)*	N/A	N/A			√		R
43	Flying Horse Transformer	2029	$8.30				CSU	L
44	Smoky Hill Third Transformer *(Duplicate with No. 62, entry exists/remains for clarity)*	N/A	N/A			√		R
45	Fort Morgan Capacitor Bank Replacement Project	2030	$4.00				WAPA	R
46	Sidney - Holcomb 345 kV	2030	1051				√	R
47	Weld KV1A Replacement and Breaker and Half Project	2030	$13.80				WAPA	R, L
48	West Sand Creek Interconnect	2030	$19.40		√			G
49	Ault Transformer Replacement	2030	$10.00				WAPA	R

Table 1: Transmission Projects included in the 2026 Plan [1]

Map and Project No.	Project Name	In-Svc	Cost ($ millions)	BH	TS	PS	Other	Purpose
50	Leetsdale to Harrison 115 kV Circuit 9955 Uprate	2031	$124.30			√		R
51	Northern Colorado Area Plan (formerly Ault-Cloverly 230/115 kV Transmission) Project (*Duplicate with No. 5, entry exists/remains for clarity*)	N/A	N/A			√		L,R
52	Colorado's Power Pathway – Segments 2 and 3	2025	$615			√		G
53	Colorado's Power Pathway – Segment 1	2026	$276			√		G
54	Pathway Voltage Control / Reactive Support	2027	$350.8			√		G,R
55	Circuit 5709: Greenwood – Arapahoe Uprate	2027	$12.7			√		R
56	Colorado's Power Pathway – Segments 4 and 5	2027	$802			√		G
57	PI-2024-06 Generation Interconnection Substation	2028	TBD			√		G
58	Arapahoe Substation Upgrades	2029	$37.0			√		R
59	Circuit 9335: Arapahoe – South Tap – Bancroft Uprate	2029	$37.5			√		R
60	Climax – Robinson Rack – Gilman 115 kV	2029	TBD			√		R
61	Daniels Park Substation Upgrades	2029	$24.3			√		R
62	Smoky Hill Substation Upgrade	2029	$32.6			√		R
63	Circuit 5107: Daniels Park - Santa Fe Uprate	2030	$12.2			√		R
64	Circuit 5717: Greenwood – Monaco Series Reactor	2030	$14.2			√		R
65	Circuit 9332: Arapahoe - Air Liquide Tap - South - Gray Street Uprate	2030	See South Substation Upgrade, Circuit 9335 costs			√		R

Table 1: Transmission Projects included in the 2026 Plan [1]

Map and Project No.	Project Name	In-Svc	Cost ($ millions)	BH	TS	PS	Other	Purpose
66	Circuit 9542: Cherokee - New Substation A	2030	$167.7			√		R
67	Circuit 9546: Cherokee - Mapleton - New Substation A Uprate	2030	$78.5			√		R
68	Circuit 9549: Cherokee -Conoco - New Substation A Uprate	2030	$15.8			√		R
69	Circuits 5167 and 5285: Smoky Hill - Buckley - Tollgate - Jewell – Leetsdale Uprate	2030	$39.2			√		R
70	New 115 kV Transmission Line: Cherokee - New Substation A	2030	$4.1			√		R
71	South Substation Upgrade	2030	$95.2			√		R
72	Circuit 5625: Denver Terminal – Elati Uprate	2031	$66.8			√		R
73	New Substation A	2031	$113.0			√		R
74	Carbondale – Crystal 115 kV Transmission	TBD	TBD			√		R, L
75	Central Weld Reliability Loop (formerly Weld-Rosedale-Box Elder – Ennis 230/115kV)	TBD	TBD			√		L,G,R
76	Gateway South – Craig/Hayden Area Transmission	TBD	TBD			√		R
77	Glenwood-Rifle 115 kV Transmission	TBD	TBD			√		L,R
78	Lamar DC Tie Replacement	TBD	TBD			√		G,L,R
79	New Distribution Substations	TBD	TBD			√		L,R
80	Northern Colorado Transmission	TBD	TBD			√		R
81	Pathway Voltage Control/Support (*Duplicate with No. 54, entry exists/remains for clarity*)	N/A	N/A			√		R
82	Poncha – Front Range 230 kV	TBD	TBD			√		G

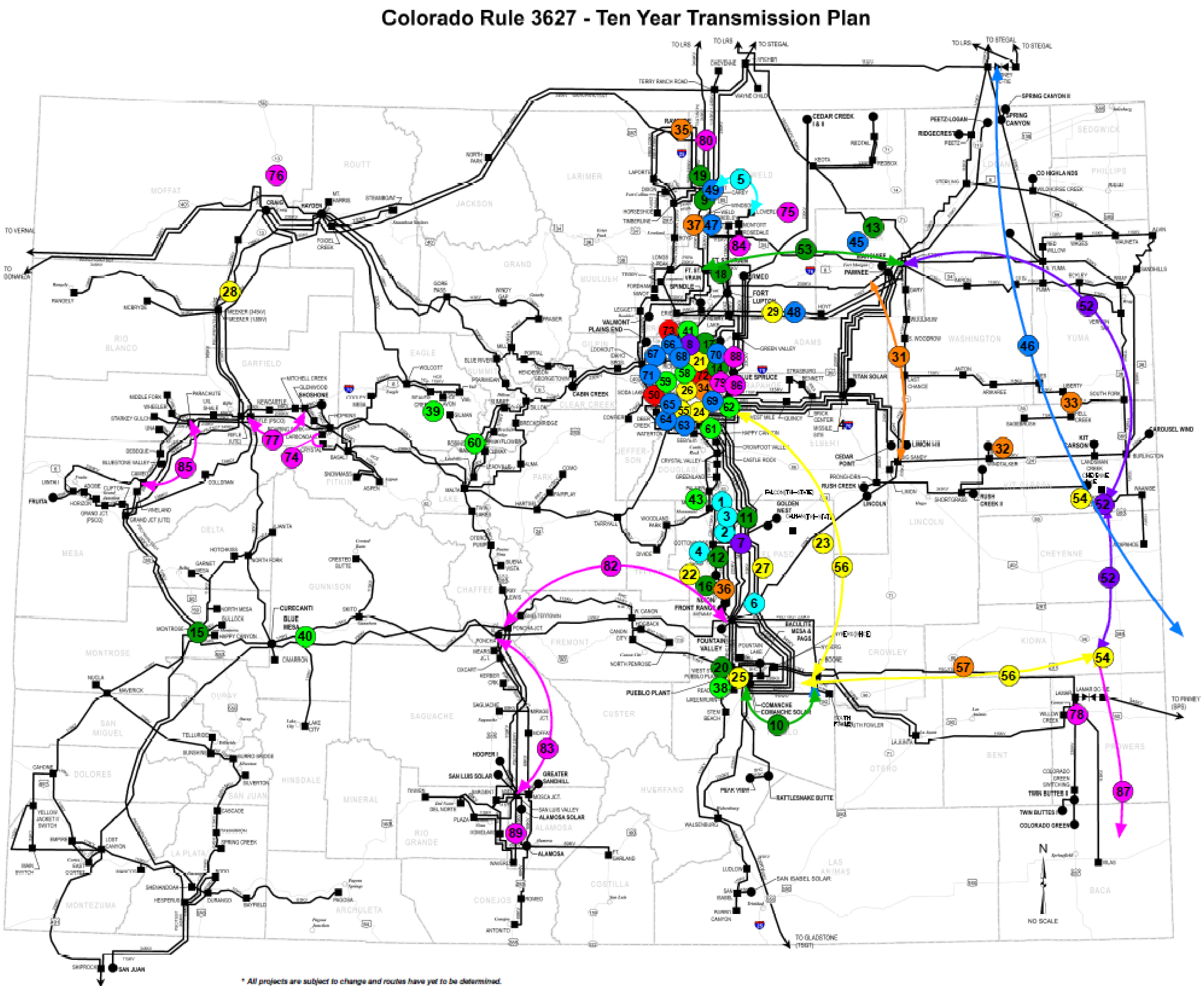
Table 1: Transmission Projects included in the 2026 Plan [1]

Map and Project No.	Project Name	In-Svc	Cost ($ millions)	BH	TS	PS	Other	Purpose
83	San Luis Valley-Poncha 230 kV Line #2[2]	TBD	TBD		√	√		R,G
84	Weld-Rosedale-Box Elder-Ennis 230/115 kV	TBD	TBD			√		L,G,R
85	Parachute-Cameo 230 kV #2 Transmission	TBD	TBD			√		R
86	Just Transition Solicitation Conceptual Network Upgrades	TBD	TBD			√		G
87	May Valley – Longhorn Extension	TBD	TBD			√		G
88	New Large Customers Network Upgrades	TBD	TBD			√		L
89	San Luis Valley Reliability Upgrades	TBD	TBD			√		R

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 2026 Plan



2024

1 Flying Horse Flow Mitigation (CSU)

2 Fuller Transformer (CSU)

3 Horizon Substation (CSU)

4 Kettle Creek Transformer (CSU)

5 Northern Colorado Area Plan (formerly Ault - Cloverly 230/115kV Transmission Project) (PSCo)

6 Pike Solar and BESS (CSU)

2025

7 Fuller BESS (CSU)

8 Metro Water Recovery Substation (100% customer funded) (PSCo)

52 Colorado Power Pathway - Segments 2 and 3 (PSCo)

2026

9 Black Hollow Sun (BHA) Project (PRPA)

10 Boone - Huckleberry 230kV Line (TSGT)

11 Claremont Transformer (CSU)

12 Horizon Transformer (New, SCU)

13 Iron Mountain 115 kV Interconnect (INew, TSGT)

14 Kestrel (formerly Project Bronco) Distribution Substation (100% customer funded) (PSCo)

15 Montrose 115 kV Interconnect (TSGT)

16 Nixon - Kelker 230kV Line Uprate (CSU)

17 Poder Distribution Substation (PSCo)

18 Slater Double Circuit Conversion (TSGT)

19 Weld Battery Energy Storage System (New, PRPA)

20 West Station to Portland 115 kV Rebuild (New, BHCE)

53 Colorado Power Pathway - Segment 1 (PSCo)

2027

21 Barker Distribution Substation (PSCo)

22 Central System Imrovements (CSU)

23 Cross Point 230/69 Kv Delivery Point (TSGT)

24 Daniels Park to Greenwood (Double) Circuit 5707 & 5111 Uprate (PSCo)

25 Hyde Park115/13.2 kV Transformer Addidtion (New, BHCE)

26 Leetsdale - Elati 230 kV Circuit 5283 Undergroung Transmission Line Upgrade (PSCo)

27 Rolling Meadows 115 kV Delivery Point (TSGT)

28 Sulfur Creek 138 kV Delivery Point (New, TSGT)

29 Sand Creek Switchyard (New, WAPA)

54 Pathway Voltage Control/Reactive Support (New, PSCo)

55 Circuit 5709 Greenwood - Arapahoe Uprate (New, PSCo)

56 Colorado Power Pathway - Segments 4 and 5 (New, PSCo)

2028

31 Big Sandy - Badger Creek (TSGT)

32 Big Sandy - Burlington 230kV Line Update (TSGT)

33 Eastern Colorado Energy Center Interconnect (New, TSGT)

34 Greenwood Substation Bus Tie Uprate (PSCo)

35 Rawhide Bus Expansion and Aeroderivative Turbine (New, PRPA)

36 South System Improvements (CSU)

37 Weld Transformer Replacement (New, WAPA)

57 PI-2024-06 Generation Interconnection Substation (New, PSCo)

2029

38 115 kV Pueblo Plant Substation Rebuild (New, BHCE)

39 Avon - Gilman 115kV Transmission (PSCo)

40 Blue Mesa Reactor & Transformer (WAPA)

41 Cherokee to Broomfield 115 kV Circuits 9055/9558/9464 Uprate (PSCo)

43 Flying Horse Transformer (CSU)

58 Arapahoe Substation Upgrades (New, PSCo)

59 Circuit 9335 Arapahoe - South Tap - Bancroft Uprate (New, PSCo)

60 Climax - Robinson Rack- Gilman 115 kV (New, PSCo)

61 Daniels Park Substation Upgrades (New, PSCo)

62 Smoky Hill Substation Upgrade (New, PSCo)

2030

45 Fort Morgan Capacitor Bank Replacement Project (WAPA)

46 Sydney - Holcomb 345 kV (New)

47 Weld kV1A Replacement and Breaker and Half Project Replacement (WAPA)

48 West Sand Creek Interconnect (New, TSGT)

49 Ault Transformer Replacement (New, WAPA)

63 Circuit 5107: Daniels Park - Santa Fe Uprate (New, PSCo)

64 Circuit 5717: Greenwood - Monaco Series Reactor (New, PSCo)

65 Circuit 9332: Arapahoe - Air Liquide Tap - South Gray Street Uprate (New, PSCo)

66 Circuit 9542: Cherokee - New Substation A (New, PSCo)

67 Circuit 9546: Cherokee - Mapleton - New Substation A Uprate (New, PSCo)

68 Circuit 9549: Cherokee - Conoco - New Substation A Uprate (New, PSCO)

69 Circuits 5167 and 5285: Smoky Hill - Buckley - Tollgate - Jewell - Leetsdale Uprate (New, PSCO)

70 New 115 kV Transmission Line: Cherokee - New Substation A (New, PSCo)

71 South Substation Upgrade (New, PSCo)

2031

50 Leetsdale to Harrison 115 kV Circuit 9955 (PSCo)

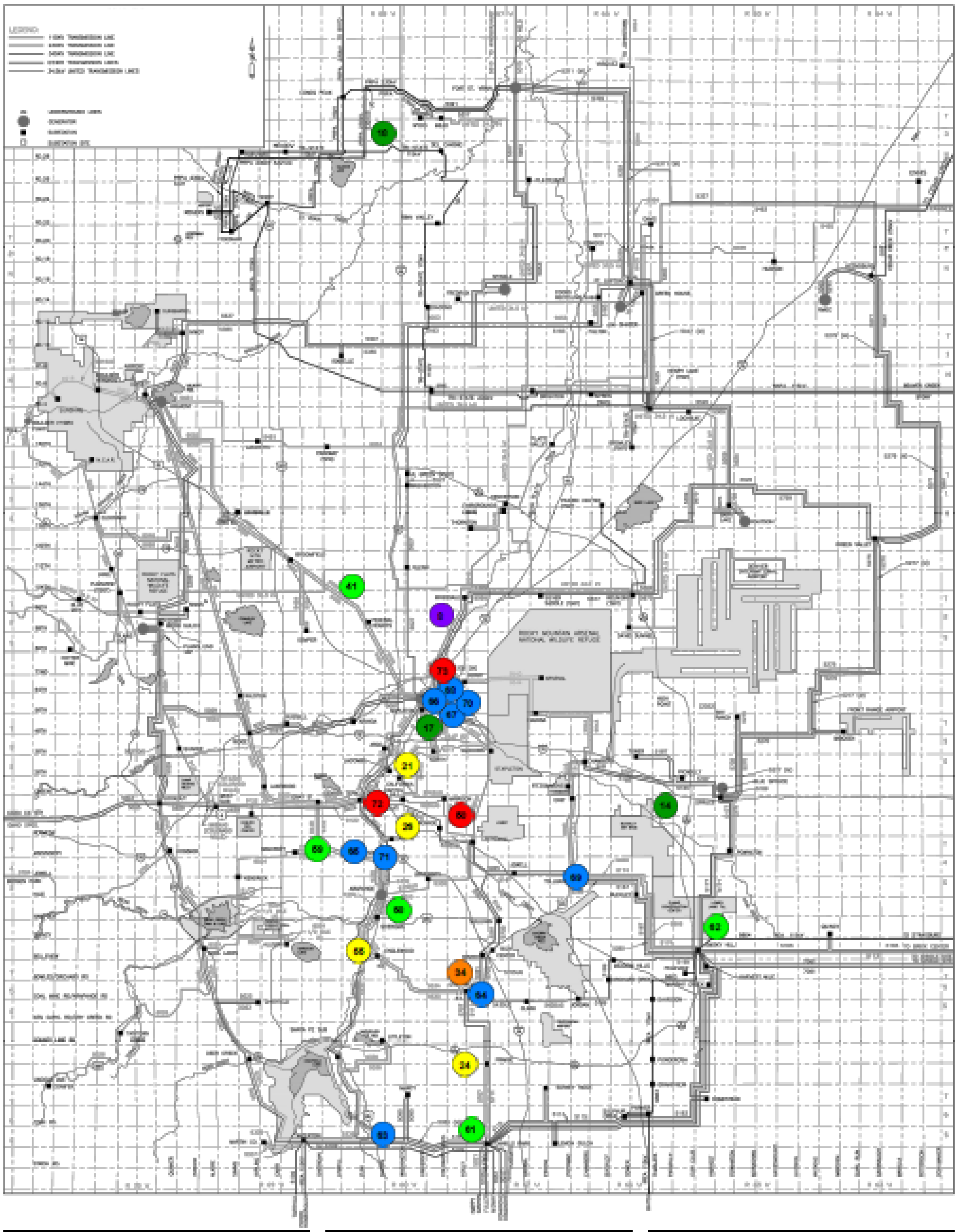
72 Circuit 5625: Denver Terminal - Elati Uprate (New, PSCo)

73 New Substation A (New, PSCo)

ISD TBD

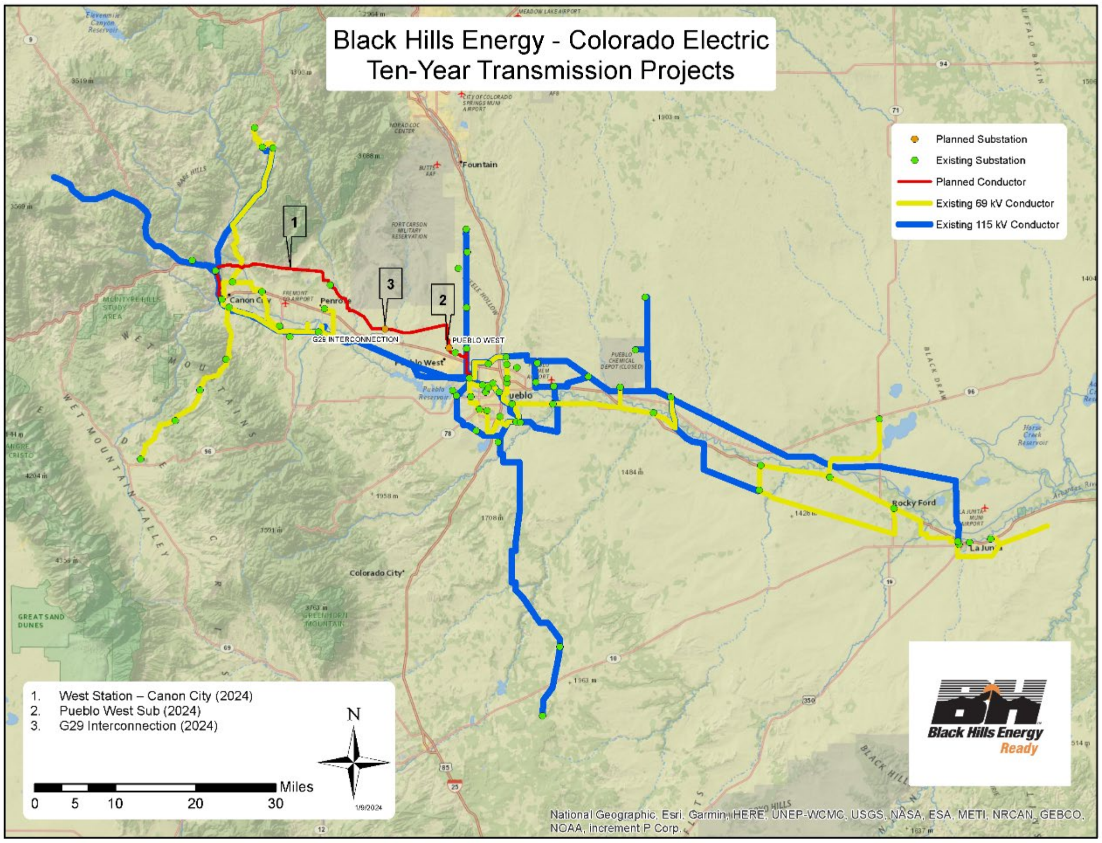
- 74 Carbondale - Crystal 115 kV Transmission (PSCo)
- 75 Central Weld Reliability Loop (formerly Weld - Rosedale - Box Elder - Ennis 230/115kV (PSCo)
- 76 Gateway South - Craig/Hayden Area Transmission (PSCo)
- 77 Glenwood - Rifle 115kV Transmission (PSCo)
- 78 Lamar DC Tie Replacement (PSCo)
- 79 New Distribution Substations (New,PSCo)
- 80 Northern Colorado Transmission (PSCo)
- 82 Poncha - Front Range 230 kV (PSCo)
- 83 San Luis Valley - Poncha 230kV Line #2 (Tri-State/PSCo)
- 84 Weld - Rosedale - Box Elder - Ennis 230/115kV (PSCo)
- 85 Parachute - Cameo 230 kV #2 Transmission (New, PSCo)
- 86 Just Transition Solicitation Conceptual Network Upgrades (New, PSCo)
- 87 May Valley - Longhorn Extention(New, PSCo)
- 88 New Large Customers Network Upgrades (New, PSCo)
- 89 San Luis Valley Reliability Upgrades New, PSCo)

Figure 2. Denver-Metro map of transmission projects in the 2026 Plan



2025	8	Metro Water Recovery Substation (100% customer funded) (New, PSCo)
2026	14	Kestrel (formerly Project Bronco) Distribution substation (100% customer funded) (New, PSCo)
	17	Poder Distribution Substation (PSCo)
	18	Slater Double Circuit Conversion (Tri-State)
2027	21	Barker Distribution Substation (PSCo)
	24	Daniels Park to Greenwood Circuit 5707 Uprate (New,PSCo)
	26	Leetsdale-Elati 230 kV Circuit Underground Transmission Line Upgrade (New, PSCo)
	56	Circuit 5709 Greenwood - Arapahoe Uprate (New, PSCo)
2028	34	Greenwood Substation Bus Tie (New, PSCo)
2029	41	Cherokee to Broomfield 115 kV Circuits 9055/9056/9464 Uprate (New, PSCo)
	58	Arapahoe Substation Upgrades (New, PSCo)
	59	Circuit 9335 Arapahoe - South Tap - Bancroft Uprate (New, PSCo)
	61	Daniels Park Substation Upgrades (New, PSCo)
	62	Smoky Hill Substation Upgrade (New, PSCo)
2030	63	Circuit 5107: Daniels Park - Santa Fe Uprate (New, PSCo)
	64	Circuit 5717: Greenwood - Monaco Series Reactor (New, PSCo)
	65	Circuit 9332: Arapahoe - Air Liquide Tap - South Gray Street Uprate (New, PSCo)
	66	Circuit 9542: Cherokee - New Substation A (New, PSCo)
	67	Circuit 9546: Cherokee - Mapleton - New Substation A Uprate (New, PSCo)
	68	Circuit 9549: Cherokee - Conoco - New Substation A Uprate (New, PSCO)
2030	69	Circuits 5167 and 5268: Smoky Hill - Buckley - Tollgate - Jewell - Leetsdale Uprate (New, PSCO)
	70	New 115 kV Transmission Line: Cherokee - New Substation A (New, PSCo)
	71	South Substation Upgrade (New, PSCo)
2031	60	Leetsdale to Harrison 115 kV Circuit 9858 Uprate (New, PSCo)
	72	Circuit 9825: Denver Terminal - Elati Uprate (New, PSCo)
	73	New Substation A (New, PSCo)
ISD TBD		Conceptual projects (TBD) not reflected on this map due to undefined project scope. These include project Numbers:
	79	New Distribution Substations (New,PSCo)
	80	Just Transition Solicitation Conceptual Network Upgrades (New, PSCo)
	83	New Large Customers Network Upgrades (New, PSCo)

Figure 3. Pueblo area map of transmission projects in the 2026 Plan



II. Transmission Planning in Colorado

A. Coordinated Planning

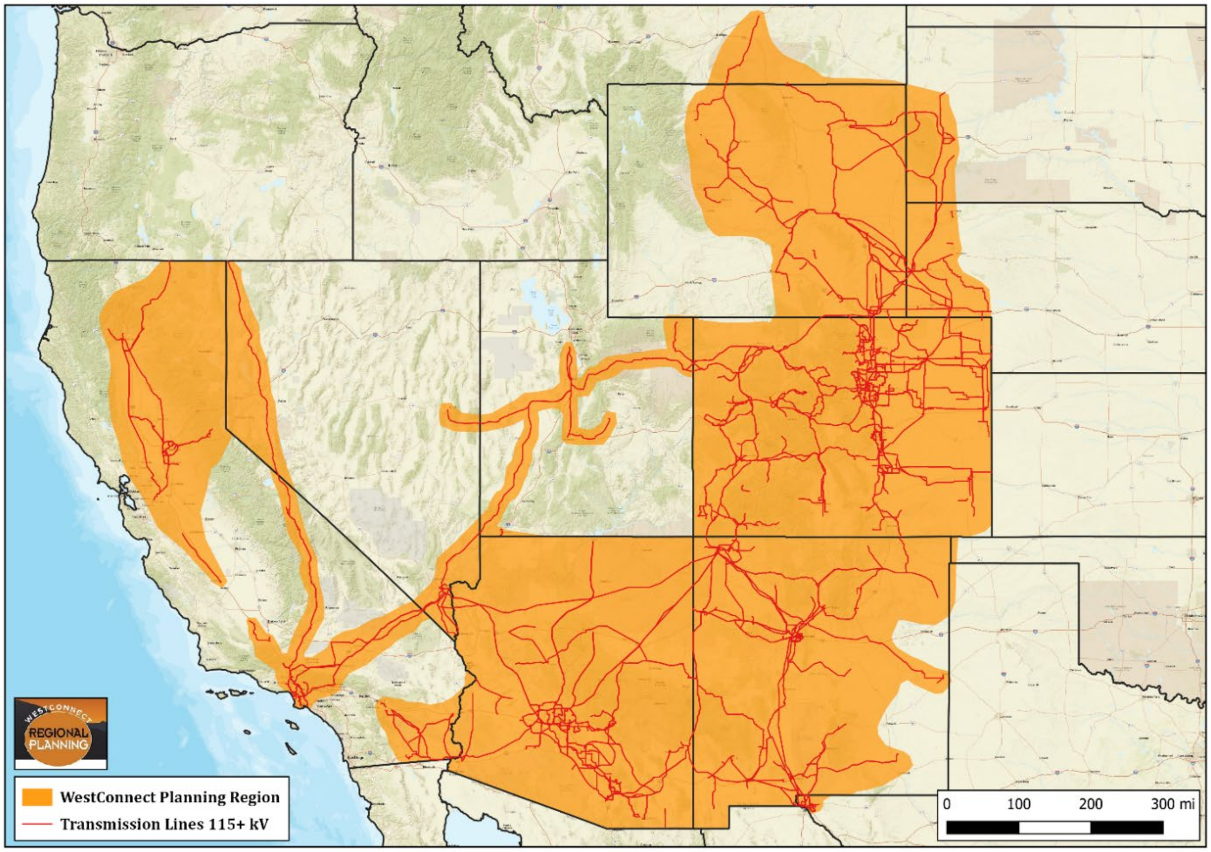
The Companies' transmission planning processes are intended to facilitate the development of electric transmission infrastructure that maintains reliability and meets load growth. Because Colorado does not have a Regional Transmission Organization ("RTO"), each TP in the state is responsible for planning its own transmission system. Starting in 2026, Tri-State will be joining the SPP RTO in the Western Interconnection. Therefore, SPP will take on some planning responsibilities for Tri-State, but Black Hills and Public Service will continue to be responsible for planning their own transmission systems. 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.

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

Figure 4. WestConnect Planning Subregional Group Footprints

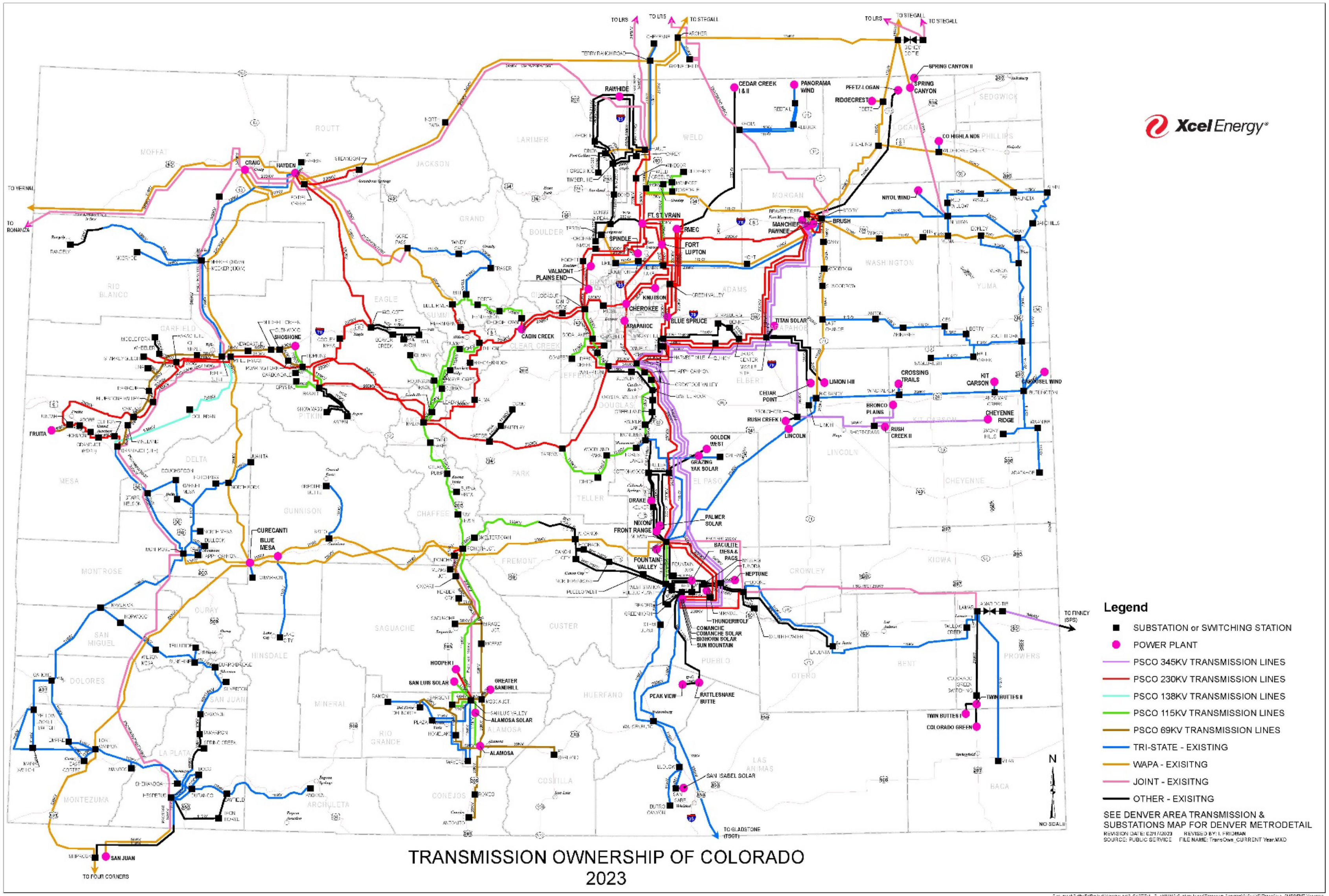


CCPG, which was formed in 1991, is a planning forum that cooperates with state and regional agencies to ensure a high degree of reliability in planning, development, and operation of the transmission system in the Rocky Mountain Region. Figure 4 shows the planning area of WestConnect.

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) public policy developments related to decarbonizing the electricity sector; (2) public policy developments expected to drive load growth; (3) public policy developments related to transmission infrastructure; and (4) additional developments. In addition to these new policy drivers, many of the drivers described in detail in the 2024 Rule 3627 Report remain relevant to this analysis and should be considered drivers for the 2026 Report as well. For example, SB19-236, which includes Clean Energy Plan requirements; SB23-016, which promotes reductions in greenhouse gas emissions; and HB23-1281, which incentivizes the use of clean hydrogen through tax credits. Descriptions of these policies can be found in the 2024 Rule 3627 Report.

1. Public Policy Developments Related to Decarbonizing the Electricity Sector

A number of legislative developments since the 2024 Rule 3627 Report target significant carbon reductions from the electricity sector. These developments, taken together, reflect a continued policy interest in shifting 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 additional transmission system improvements that focus on addressing the needs created by increasing penetrations of renewable energy resources on their systems.

a. Senate Bill 24-212, Local Governments Renewable Energy Projects

SB24-212 requires the Colorado Energy Office to cooperate with the Department of Local Affairs and the Department of Natural Resources and develop a repository of codes and ordinances that support renewable energy projects and commercial energy transmission facilities. The impetus for such development is to provide conceptual frameworks that local governments and tribal governments in Colorado may consider and adapt to benefit local circumstances and address local energy resources.

b. Senate Bill 24-218, Modernize Energy Distribution Systems

SB24-218 creates various requirements related to utility distribution systems. Specifically, the law requires an investor-owned electric utility that serves 500,000 customers or more in the state (a qualifying retail utility, or "QRU") to upgrade the QRU's distribution systems as necessary to (1) support the transportation, affordable housing, new infill housing, and building electrification policies of state and local law, including Air Quality Control Commission rules related to transportation electrification and building performance standards; (2) implement federal, state, regional, and local air quality and decarbonization targets, standards, plans, and regulations; and (3) support state agency, local agency, and local government plans and requirements related to housing, economic development, critical facilities, transportation, and building electrification. Additionally, by January 1, 2025, a QRU was required to file a plan with the Commission to implement programs for the undergrounding of utility distribution infrastructure in non-franchised areas of the QRU in the state using 1% of the area's gross electric revenues from the prior year. By February 1, 2025, a QRU was required to create and file with the Commission an application to implement a virtual power plant program, including a tariff for performance-based compensation for a qualified virtual power plant.

These filing requirements for QRUs apply to Black Hills and PSCo. On December 16, 2024, PSCo initiated Proceeding No. 24A-0574E for approval of its 2025-2029 Distribution System Plan and on January 31, 2025, PSCo filed its Aggregator Virtual Power Plant Program in Proceeding No. 25A-0061E; the proceedings are consolidated in Proceeding No. 24A-0574E. [Insert final ruling on all issues presented in the proceeding when issued in November 2025 (expected)]. On January 31, 2025, Black Hills initiated Proceeding No. 25A-0062E for approval of its 2025-2029 Distribution System Plan. [Insert final ruling on all issues presented in the proceeding when issued in November 2025 (expected)].

c. House Bill 25-1269, Building Decarbonization Measures

HB25-1269 establishes building performance standards and creates the Building Decarbonization Enterprise in the Colorado Energy Office to provide technical assistance, financing, and other programmatic support for building decarbonization measures, which include energy audits, consulting services, and energy use tracking software. Specifically, the act updates energy use benchmarking and performance standard requirements for owners of certain buildings (covered building owners), including a requirement to meet 2040 performance standards, as adopted by the Air Quality Control Commission, in consultation with the Colorado Energy Office and in consideration of recommendations made by a task force convened by the office; authorizes an alternative compliance mechanism for covered building owners to comply with certain performance standards; and updates civil penalties owed for a violation of the benchmarking requirements.

d. Senate Bill 25-037, Coal Transition Grants

SB25-037 creates and authorizes grants and assistance to assist Colorado communities affected by closures of coal-related facilities. It includes funding and assistance for Colorado coal communities' workforce, community economic development, as well as projects that help communities adapt to the loss of coal jobs and tax base. Specifically, the act requires the Office of Just Transition within the Department of Labor and Employment to prioritize awarding funding to support tier one and tier two coal transition communities experiencing socioeconomic impacts of coal closures and for opportunities for economic diversification, local community input, feasibility studies of specific proposed projects, and needs assessments.

e. House Bill 25-1040, Adding Nuclear Energy as a Clean Energy Resource

Among other things, the statutory definition of "clean energy resource" provided in C.R.S. § 40-2-125.5(2)(b) determines which energy resources may be used to meet 2050 clean energy targets. HB25-1040 adds nuclear energy to the definition of a "clean energy resource," which allows nuclear energy projects to qualify for clean energy project financing.

f. H.R. 1, United States 119th Congress

H.R. 1, signed into law on July 4, 2025 and referred to as the "One Big Beautiful Bill Act," accelerates the phaseout of federal clean energy tax credits that had previously been adopted or expanded through the Inflation Reduction Act. Tax credits for wind and solar generation will continue to be available for projects that either start construction by June 2026 or are placed in service by December 2027. Electric vehicle tax credits expired on September 30, 2025 and tax credits associated with electric vehicle charging installations will expire on June 30, 2026.

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 may be electrified, creating additional demand for electricity. For example, as electric vehicle 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 drive additional transmission needs in Colorado. Some load growth driven by these electrification and new nuclear 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. House Bill 25-1267, Support for Statewide Energy Strategies

HB25-1267 requires minimum standards for retail electric vehicle charging stations. Specifically, the act requires the Director of the Division of Oil and Public Safety in the Department of Labor and Employment to adopt rules concerning retail electric vehicle charging that set forth minimum standards relating to specifications and tolerances for retail electric vehicle charging equipment and methods of retail sale at publicly accessible electric vehicle charging stations to promote consistency in the marketplace by July 1, 2026, and to enforce the rules beginning July 1, 2027. This measure broadens the allowable uses of money in the electric vehicle grant fund within the Colorado Energy Office.

3. Public Policy Developments Related to Transmission Infrastructure

a. House Bill 25-1292, Transmission Lines in State Highway Rights-of-Way

HB25-1292 concerns the process to allow a transmission developer to locate high voltage transmission lines within a state highway right-of-way. Specifically, the act allows a transmission developer to longitudinally co-locate high voltage transmission lines within a state highway right-of-way, according to a process developed by rule by the Department of Transportation ("DOT"). Upon the request of a transmission developer, the department is required to provide to the transmission developer the best available information on potential future state highway development projects that could impact the placement of a high voltage line within a right-of-way. If the DOT and a transmission developer agree that a site may be suitable for high voltage line development and preconstruction requirements are approved, the transmission developer is required to provide a constructability, access, and maintenance report that includes mitigation strategies for potential impacts of the proposed high voltage line. The act also requires the Colorado Electric Transmission Authority, through a public-private partnership and in collaboration with the department, the Colorado Energy Office, the Commission, and other state agencies, including the Division of Parks and Wildlife, to study state highway corridors to identify potential corridors that may be suitable for high voltage transmission line development and to publish and share with specified state agencies a report on the findings of the study.

b. FERC Order No. 1920

In May 2024, the Federal Energy Regulatory Commission ("FERC") issued Order No. 1920 ("Order 1920"), a new transmission and cost allocation rule aimed at ensuring nationwide reliability. Order 1920 adopts specific requirements to address how transmission providers must conduct long-term planning for regional transmission facilities and determine how to pay for them, to ensure transmission infrastructure is built to meet current and future needs. Order 1920 includes, at a high level: (1) a requirement to conduct and periodically update long-term transmission planning to anticipate future needs; (2) a requirement to consider a broad set of benefits when planning new facilities; (3) a requirement to identify opportunities to modify in-kind replacement of existing transmission facilities to increase their transfer capability, known as “right-sizing”; and (4) an expansion of states’ role in the process of planning, selecting, and determining how to pay for transmission facilities. Order 1920 requires each transmission operator to: (1) produce a regional transmission plan of at least twenty years to identify long-term needs and the facilities to meet them; (2) conduct such planning once every five years using a plausible and diverse set of at least three scenarios using specific factors and the best available data; (3) apply specific benefits to determine whether any regional proposals will efficiently and cost-effectively address long-term transmission needs; (4) include an evaluation process; (5) include a process that gives states and interconnection customers the opportunity to fund all or a portion of the cost of a long-term regional transmission facility; (6) consider transmission facilities that address interconnection-related needs identified multiple times in existing generator interconnection processes, but that have not been built; (7) reevaluate long-term regional transmission facilities that were previously selected due to delays or cost overruns; and (8) consider the use of Grid Enhancing Technologies such as dynamic line ratings, advanced power flow control devices, advanced conductors, and transmission switching.

4. Additional Public Policy Developments

a. Senate Bill 25-182, Embodied Carbon Reduction

SB25-182 expands the Industrial Clean Energy Tax Credit (created through House Bill 23-1272), which included tax incentives for industrial emissions studies and greenhouse gas emissions reductions. SB25-182’s expansion of the tax credit includes “embodied carbon improvements,” investments in producing asphalt and asphalt mixtures, cement and concrete mixtures, and steel that result in the reduction of the material’s embodied emissions. The bill adds embodied-carbon improvements to the list of eligible “new energy improvements” for property-assessed clean energy financing and encourages reductions in embodied carbon in construction and makes embodied-carbon improvements eligible under certain clean-energy/PACE-style financing programs. While it does not directly affect the electric sector, this bill may drive additional electrification in the covered industries.

C. Emerging Issues

1. Organized Markets

Colorado Senate Bill 21-072 requires, in part (C.R.S. § 40-5-108), that Colorado transmission utilities[4] join an Organized Wholesale Market ("OWM") on or before January 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 and that there is no viable OWM the utility can join by January 1, 2030, or the Commission has determined that requiring the utility to join an OWM is not in the public interest. 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).

On June 16, 2025, in Proceeding No. 25A-0266E, Tri-State submitted its application to the Commission for a finding that the Southwest Power Pool Regional Transmission Organization in the Western Interconnection ("SPP RTO West") is a Statutory OWM in accordance with C.R.S. § 40-5-108(1) and a finding that its expanded participation in SPP RTO West is in the public interest pursuant to Commission Rules 3754(d) and (f). On December 16, 2025, the Commission issued Decision No. C25-0906 granting Tri-State's application and finding that the SPP RTO West is a Statutory OWM and that Tri-State's decision to expand its participation in SPP RTO West is in the public interest.

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

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.

TPL-008-1 is a new reliability standard developed by the North American Electric Reliability Corporation (NERC), approved by NERC in December 2024 and FERC in February 2025, that addresses transmission system planning for extreme temperature events (both extreme heat and extreme cold). The new standard requires planning coordinators and transmission planners to conduct an "Extreme Temperature Assessment," which includes modeling and analysis of how the system performs under extreme cold and heat benchmark events, at least every five years. Such analysis must include both steady-state and transient stability under the extreme temperature conditions, taking into account relevant contingencies. Entities are required to coordinate development of benchmark planning cases and sensitivity cases for those events. If the system fails to meet the performance standard established in the assessments, the entity must develop a corrective action plan.

D. Alternative Technologies

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. FERC Order No. 1920 requires transmission providers to consider DLR for each identified transmission need; thus, the Companies will need to consider such an alternative technology in compliance with FERC Order No. 1920. However, such consideration does not impact this report.

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 were required to implement AAR in compliance with FERC Order No. 881 by July 12, 2025. On July 8, 2022, Black Hills submitted its compliance filing for FERC Order No. 881.[5] On July 12, 2022, Tri-State[6] and PSCo[7] submitted their compliance filings for FERC Order No. 881. 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.

[5] Docket No. ER22-2303-000.

[6] Docket No. ER22-2360-000.

[7] Docket No. ER22-2356-000.

3. Transmission System Topology Optimization

Topology optimization is transmission system reconfiguration, through automatic switching of circuit breakers open or closed, 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 transmission 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 transmission 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.

FERC Order No. 1920 requires transmission providers to consider advanced power flow control devices for each identified transmission need.

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 Reinforced ("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.

FERC Order No. 1920 requires transmission providers to consider advanced or special conductors for each identified transmission need.

III. Company Plan Narratives

A. Black Hills 10-Year Plan Overview

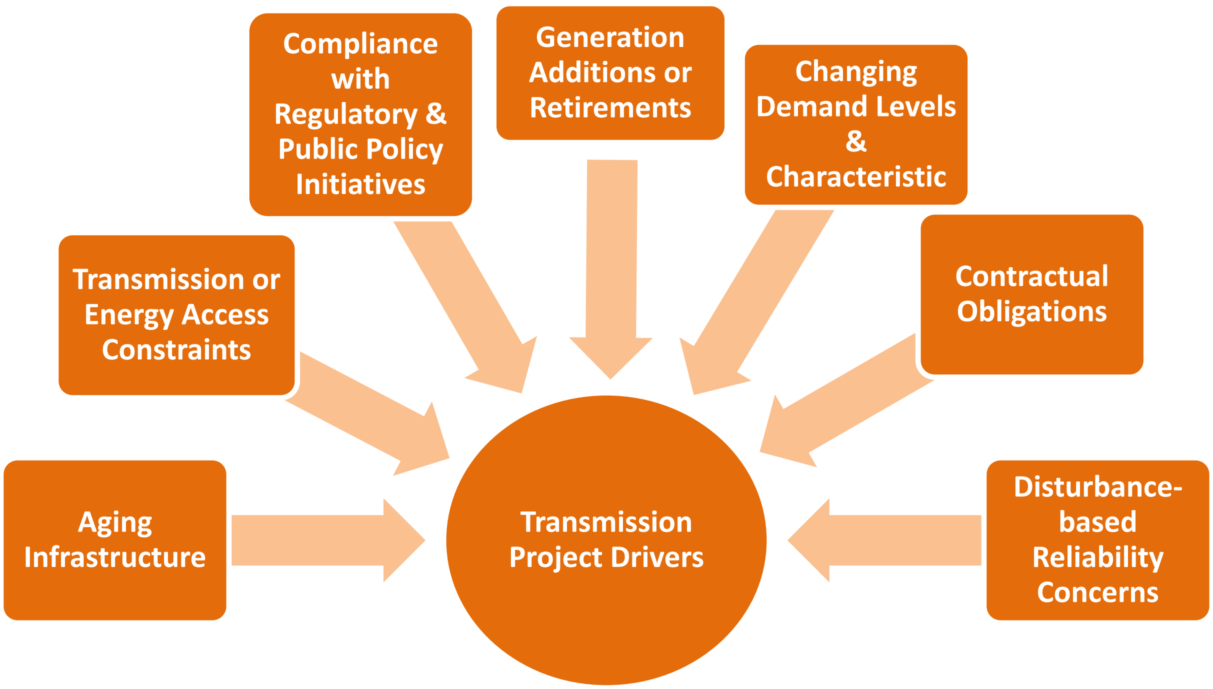
1. Black Hills Service Territory

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. Clean Energy Plan

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 filed its 120-day report indicating its preferred portfolio and other portfolios on April 17, 2024. On September 4, 2024, the Commission issued Decision No. C24-0634, which changed the portfolio of resources to replace the 200 MW utility-owned solar with a 200 MW solar PPA, approved a 100 MW PPA solar project and a built transfer agreement (BTA) for a 50 MW battery storage project. On October 4, 2024, the Commission issued Decision No. C24-0715 to allow for the possibility of a BTA for the 200 MW solar project. On August 29, 2025, the Company filed a Motion requesting the Commission provide guidance on whether the Company should continue to seek and execute contracts with developers for the two remaining projects in the CEP, a 100 MW BTA solar project and a 200 MW PPA solar project, in the light of recently increased pricing. The Company filed updated modeling runs on October 3, 2025, then the Commission issued Decision No. C25-0805 stating that the Company should move forward with the 200 MW PPA solar project and not the 100 MW BTA solar project. Accordingly, the CEP was reduced from 350 MW (which includes a 50 MW battery storage project already fully approved by the Commission) to 250 MW. The Company is pursuing the completion of the 50 MW battery project and execution of the 200 MW solar PPA contract.

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 2025 Plan largely reflect the continued strategy of infrastructure upgrades of additions to enhance reliability, thus the Plan focused on reliability-driven equipment replacements or upgrades.

In the 2025 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 2024 10-Year Plan, Black Hills has completed the following projects: Pueblo West 115/13.2 kV Distribution Substation, Canon West 230/115 kV Transformer Upgrade, Nyberg – La Junta (Boone Bypass) 115 kV and portions of the West Station – Canon West 115 kV Rebuild Black Hills identified three planned projects within the upcoming 10-year planning horizon that represent $56 million in capital expenditures between 2025 and 2029. The projects were identified to increase reliability within Black Hills' network transmission system 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

One projects, shown in Table 2, addresses reliability and aging infrastructure concerns in the Cañon City area.

Table 1. Cañon City area projects included in the Black Hills 2025 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
West Station – Canon West 115 kV Rebuild	2026	$41.6	Not required. Decision No. C23-0810

The West Station – Portland 115 kV line will be rebuilt to replace aging infrastructure and address overloads identified in generation interconnection studies and summer peak operational studies. This is the last portion of the West Station – Canon West 115 kV Rebuild.

Pueblo area

Two projects, shown in Table 3, address reliability and contingency concerns in the Pueblo area. These projects will address transmission overloads identified in transmission planning studies as well as distribution reliability concerns identified in the 2023 Distribution System Plan (DSP).

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

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
115kV Pueblo Plant Substation Rebuild	2029	$6.5	TBD
Hyde Park 115/13.2 kV Transformer Addition	2027	$4.0	TBD

The 115kV Pueblo Plant Substation will be rebuilt to address the limiting substation equipment and improve the load serving redundancy. The Hyde Park 115/13.2 kV transformer addition will address N-1 risks and expected load growth. The Hyde Park transformer additional will also offload the Pueblo Plant substation to support the 115 kV Pueblo Plant Substation Rebuild.

Boone & Rocky Ford area

One project, shown in Table 4, addresses reliability concerns in the Rocky Ford area.

Table 3. Boone & Rocky Ford area projects included in the Black Hills 2024 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
La Junta 115/69 kV Transformer Upgrade	2029	$3.9	TBD

The La Junta 115/69 kV Transformer Upgrade will mitigate overloads that have been identified in annual transmission planning studies and summer peak operational studies. The overloads are currently mitigated with local diesel generation. The diesel generation is expected to be retired in 2029 and will no longer be available for operational mitigation.

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 considered 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 discussion 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 40 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 2026 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 2026 Plan, it is important to recognize the key differences between Tri-State and other Colorado utilities. Tri-State is a cooperative owned by its 43 members, including 40 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 the rates charged to Tri-State's Utility Members is determined by a FERC approved Formula Rate (ER24-2171). 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 2026 Transmission Plan includes transmission, substation, and distribution projects throughout Wyoming, Nebraska, Colorado, and New Mexico, this summary focuses on the larger transmission projects in Colorado. Many of these projects provide multiple benefits in terms of load serving, reliability improvements, congestion relief, or the accommodation of new generation. It should be noted that the 2026 Plan includes some projects listed in the 2024 and earlier Plans.

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 were not initially known, Tri-State anticipated 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 4. Load-serving projects included in the Tri-State 2026 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Big Sandy-Badger Creek 230 kV Line	2028	$78.5	Issued
Cross Point 230/69kV Delivery Point	2027	$22.7	NR
Rolling Meadows 115 kV Delivery Point	2027	$10.4	NR
Iron Mountain Delivery Point	2026	$14.8	NR
Sulfer Creek Delivery Point	2027	$6.4	

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.

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.

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.

Iron Mountain 115 kV Delivery Point

This project consists of a newly constructed 115/12.47 kV delivery point located on WAPA's Airport – Windsor Tap – Whitney 115 kV line. This substation is needed to serve new residential, small commercial, and associated infrastructure between Loveland and Windsor, CO.Sulfer Creek Deliver Point

This project consists of tapping Tri-State's 138kV Axial Basin – Meeker transmission line approximately 7.5 miles northeast of the Meeker Substation and installing a tap station to serve White River Electric Association's new 138 kV feed out of the Welle Substation. This project will include a box structure with all associated disconnect switches, dead end structures, instrument transformers and other various SCADA, metering, and telecom systems. This will improve reliability to the member, White River Electric Association, as it will be able to retire over 17 miles of aging transmission between Welle and Axial Basin.

Table 5. Reliability 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	$78.5	Issued
Big Sandy-Burlington 230 kV Line Uprate	2028	$13.9	NR
Cross Point 230/69kV Delivery Point	2027	$22.7	NR
La Junta 115 kV Tie**	TBD	TBD	NR
San Luis Valley-Poncha 230 kV Line #2**	TBD	TBD	Req'd
Slater Double Circuit Conversion	2026	$7.6	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.

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.

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 6. Generation Congestion projects in the Tri-State 2026 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Big Sandy-Badger Creek 230 kV Line	2028	$78.5	Issued
Big Sandy-Burlington 230 kV Line Uprate	2028	$13.9	NR
Boone-Huckleberry 230 kV Line	2026	$40.6	Issued
Montrose 115 kV Interconnect	2026	$3.7	
Eastern Colorado Energy Center Interconnect	2028	$16.5	
West Sand Creek Interconnect	2030	$19.4	

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.

Montrose 115 kV Interconnect

The project is required to connect the High Country BESS project to Tri-State's transmission system. The interconnection facilities will consist of a new 115 kV line bay, including breaker and associated switches, to the existing Montrose 115 kV station. This is a 100 MW BESS project that has an executed Large Generator Interconnection Agreement. There is no transformer or transmission line within the scope of this project.

Eastern Colorado Energy Center Interconnect

This project is required to connect the Eastern Colorado Energy Center Project to Tri-State's transmission system. The interconnection facilities will consist of rebuilding the existing Hell Creek Tap to a new 4 breaker ring bus with associated switches and renamed Devils Switch. This is a 90 MW interconnection solar/storage project that has an executed Large Generator Interconnection Agreement. The terminals for each existing line will be designed for 1229 Amps. There is no transformer or transmission line within the scope of the project.

West Sand Creek Interconnect

This project is required to connect the Prospect Solar project to Tri-State's transmission system. The interconnection facilities will consist of a new 230 kV three breaker ring substation. This is a 199 MW solar and 100 MW BESS project that has an executed Large Generator Interconnection Agreement. There is no transformer or transmission line within the scope of this project.

3. Tri-State Alternative Technologies

There are no new transmission projects in Tri-State's 2026 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 2026 10-Year plan is contained in Appendix E. Additional information and supporting documentation can be found on Tri-State's website.

C. Public Service 10-Year Plan Overview

Public Service is an investor-owned utility serving approximately 1.6 million electric customers in the State of Colorado.[8] Public Service serves approximately 75 percent of the State's population. Its electric system is summer peaking with a 2025 peak customer (retail + wholesale requirements) demand of 7,010 MW. The entire Public Service transmission network is located within the State of Colorado and consists of nearly 5,300 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

[8] Public Service is one of four utility operating companies of Xcel Energy, Inc, along with Northern States Power Company – Minnesota, Northern States Power Company – Wisconsin, and Southwestern Public Service Company.

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 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 towards cleaner energy sources. Xcel Energy, Public Service's parent company, aspires to deliver 100% carbon-free electricity to customers by 2050, with an interim goal of reducing carbon emissions from electric generation 80% below 2005 levels by 2030. In addition to transitioning to cleaner energy resources, Public Service is also forecasting significant load growth driven by residential and commercial development, expanded electrification of transportation and heating, and large new customer requests related to development of new energy-intensive facilities such as data centers or manufacturing facilities.

In Colorado, Public Service's implementation of its 2030 clean energy goals comes through the Clean Energy Plan process created in SB19-236. The Commission approved a Clean Energy Plan in Proceeding No. 21A-0141E that results in the acquisition of significant new wind, solar, and energy storage resources through 2028. Public Service's Just Transition Solicitation, a resource plan intended to continue the clean energy transition and further address the effects of the clean energy transition on Colorado communities while also accounting for additional near-term load growth, is before the Commission in Proceeding No. 24A-0442E with a Phase II resource solicitation expected to be issued in 2026. Additionally, in response to the phase-out of federal clean energy tax benefits enacted through H.R.1 in 2025, Public Service jointly proposed with Commission Staff, the Office of the Utility Consumer Advocate, and the Colorado Energy Office a "Near-Term Procurement" in Proceeding No. 21A-0141E to acquire up to 4,000 MW of tax-advantaged new renewable generation and 500 MW additional thermal and energy storage resources to support the integration of variable renewable resources.

Public Service has completed a solicitation for generation bids and approval of a resource portfolio in the Near-Term Procurement is currently pending before the Commission.

The combined result of these generation and demand factors will significantly affect transmission planning into the future, however, the levels of uncertainty associated with new generation and new customer demand affect Public Service's ability to identify needed new transmission projects with sufficiently long lead times aligned with the years covered by this Plan. Additionally, many of the specific transmission projects described in this Ten-Year Plan are still in the preliminary stages of transmission planning analysis and cannot yet be affirmed by Public Service as Planned Projects.

In this Ten-Year Plan, through the inclusion of Planned Projects and Conceptual Projects, as well as a discussion of the near-term drivers of additional transmission system enhancement and expansion, Public Service seeks to capture the breadth of transmission system needs over the course of the next decade to maintain system reliability, accommodate new clean energy generating resources, and support new customer demand. However, additional projects that are not reflected in this 10-Year Plan are likely to be needed in the timeframe covered by this plan. Given the iterative nature of planning processes, there are currently additional ongoing study efforts whose results are not yet mature enough to result in the identification of additional planned or conceptual projects and additional near-term drivers of transmission needs are likely to emerge as additional studies are completed. In particular, additional transmission projects associated with the Denver Metro constraint are likely to be identified as additional studies are conducted of generation portfolio retirements and additions and of growing customer demand, both from new and existing customers on the distribution system as well as large load requests to connect to the transmission system. As demand grows within Public Service's primary load center in the Denver Metro area, additional transmission capacity achieved through upgrades to existing facilities or the construction of new transmission paths within the Denver Metro area are likely to be necessary. Public Service expects that such upgrades are likely to be necessary along the northern While the potential for development of generation resources or demand flexibility and management programs within the Denver Metro area load center has the potential to affect specific transmission system needs, the overall levels of load growth forecast on the Public Service system still point to substantial transmission expansion needs over the next 10 years.

1. Public Service Planning Process

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

The Public Service transmission planning process is intended to facilitate the development of electric infrastructure that maintains system reliability, responds to interconnection and transmission service requests, meets load growth and enables integration of new resources, and fulfills the following principles:

- Maintain reliable electric service by 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 which go into the planning process, including customer load growth, accommodation of new resources, retirement of existing resources, compliance with state and federal rules and standards, replacement of aging infrastructure, and public policy initiatives. Each of these individual variables may carry with them some level of uncertainty. As transmission planners consider different planning horizons, such as two-, five- and 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 advanced transmission technologies (“ATT”) and non-wire alternatives 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 advanced transmission technologies and non-wires alternatives, is an inherent part of Public Service’s planning process. Public Service follows its established process for evaluating project alternatives per the Xcel Energy 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, and ATTs are 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 ATTs consistent with 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 or GETs for all new planned transmission projects identified in the Ten-Year Plan. Details about the analysis of ATTs are discussed in project descriptions below, as applicable. ATTs will be fully evaluated for all Conceptual Projects before those projects become Planned. Public Service does not have a Planned Project for which an NWA has been selected in this Ten-Year Plan.

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 both new transmission facilities as well as capacity upgrades to existing transmission facilities, and may include transmission line extensions constructed pursuant to Public Service's Commission-approved retail electric tariff to accommodate new large customer load interconnection requests. 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 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 previous resource acquisitions such as the 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP")[9] or future resource plans such as the Near-Term Procurement ("NTP")[10] and Just Transition Solicitation ("JTS")[11]. As Public Service's transmission analysis provided in support of Phase I of the JTS demonstrates, Public Service expects that the accelerating growth in customer demand as well as the continued 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 statewide transmission system. Further, as new renewable energy resources come online, those changes in flow across the system may require additional voltage support equipment. As additional studies are completed, and as resource acquisition decisions are finalized allowing for the completion of follow-on transmission studies associated with specific generation portfolios, Public Service will continue to refine and adjust transmission plans as necessary to ensure that customers receive safe, reliable, affordable, and clean electricity service.

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

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

[11] Proceeding No. 24A-0442E.

Table 8 below lists Public Service's planned and conceptual transmission projects identified within the 10-year planning horizon of this Report. For completed projects, the costs listed are the final cost that Public Service incurred in constructing the project. For planned projects, the costs listed are the project costs that were identified in Public Service's most recent Rule 3206 Annual Report filing or CPCN application. Conceptual projects, as well as some planned projects, are listed with cost estimates of "TBD" as Public Service has not yet completed sufficient development activities to develop a reliable project cost estimate associated with the project.

Public Service does not provide a total estimated capital cost for transmission expansion necessary to meet estimated 2036 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. 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 7. Public Service 10-Year Plan Projects

Project Name	ISD	Capital Cost[12] ($ millions)	Year Study Completed	WECC Base Case Studied	BAA Winter Peak Demand (MW)[13]	BAA Summer Peak Demand (MW)	CPCN[14]
Transmission Projects Completed 2024-2026							
Colorado's Power Pathway – Segments 2 and 3	2025	$615	2021	2030HS1	N/A	10,273	G
Northern Colorado Area Plan (formerly Ault-Cloverly 230/115 kV Transmission) Project	2024	$125.7	2017	2026HS2	N/A	9,103	G
Colorado Springs Utilities Unintended Flow Mitigation Project	2024	$12.4	2021	N/A	N/A	N/A	NR
Metro Water Recovery Substation (100% customer funded)	2025	$12.4	2021	N/A	N/A	N/A	NR
New Planned Transmission Projects							
Daniels Park Substation Upgrades	2029	$24.3	2024	2028HS	N/A	10,119	G
Circuits 5111 and 5707: Daniels Park – Prairie – Greenwood Uprate	2027	$19.7	2024	2028HS	N/A	10,119	G
Circuit 5709: Greenwood – Arapahoe Uprate	2027	$12.7	2024	2028HS	N/A	10,119	G
Greenwood Substation Upgrades	2028	$1.2	2024	2028HS	N/A	10,119	G
Circuit 5717: Greenwood – Monaco Series Reactor	2030	$14.2	2024	2028HS	N/A	10,119	G
Arapahoe Substation Upgrades	2029	$37.1	2024	2028HS	N/A	10,119	G
Circuit 9335: Arapahoe – South Tap – Bancroft Uprate	2029	$37.5	2024	2028HS	N/A	10,119	G
Circuit 9332: Arapahoe - Air Liquide Tap - South - Gray Street Uprate	2030	*See* South Substation Upgrade,	2024	2028HS	N/A	10,119	G

[12] 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.

[13] Peak demands are not generally applicable to all project analyses. Peak demand values are calculated at the time of the study based on loads within the Balancing Authority Area and may not reflect current peak demand calculations.

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

Project Name	ISD	Capital Cost[12] ($ millions)	Year Study Completed	WECC Base Case Studied	BAA Winter Peak Demand (MW)[13]	BAA Summer Peak Demand (MW)	CPCN[14]
		Circuit 9335 costs					
South Substation Upgrade	2030	$95.2	2024	2028HS	N/A	10,119	G
Circuit 5107: Daniels Park - Santa Fe Uprate	2030	$12.2	2024	2028HS	N/A	10,119	G
Circuits 5167 and 5285: Smoky Hill - Buckley - Tollgate - Jewell – Leetsdale Uprate	2030	$39.2	2024	2028HS	N/A	10,119	G
Circuit 5625: Denver Terminal – Elati Uprate	2031	$66.8	2024	2028HS	N/A	10,119	G
Circuit 9955: Leetsdale – Harrison Uprate	2031	$124.3	2024	2028HS	N/A	10,119	G
Smoky Hill Substation Upgrade	2029	$32.6	2024	2028HS	N/A	10,119	G
New Substation A	2031	$113	2024	2028HS	N/A	10,119	G
New 115 kV Transmission Line: Cherokee - New Substation A	2030	$4.1	2024	2028HS	N/A	10,119	G
Circuit 9542: Cherokee - New Substation A	2030	$167.7	2024	2028HS	N/A	10,119	G
Circuit 9546: Cherokee - Mapleton - New Substation A Uprate	2030	$78.5	2024	2028HS	N/A	10,119	G
Circuit 9549: Cherokee - Conoco - New Substation A Uprate	2030	$15.8	2024	2028HS	N/A	10,119	G
Circuits 9055, 9558, and 9464: Cherokee - Federal Heights - Semper – Broomfield Uprate	2029	$58.2	2024	2028HS	N/A	10,119	G
PI-2024-06 Generation Interconnection Substation	2028	TBD	2025	2029HS2a	N/A	10,119	U
Previously Identified Planned Projects							
Colorado’s Power Pathway – Segment 1	2026	$276	2021	2030HS1	N/A	10,273	G
Colorado’s Power Pathway – Segments 4 and 5	2027	$802	2021	2030HS1	N/A	10,273	G
May Valley – Longhorn Extension	TBD	TBD	2021	2030HS1	N/A	10,273	G (conditional)
Pathway Voltage Control / Reactive Support	2027	$350.8	2024	2030HS1	N/A	10,273	P
Circuit 5283: Leetsdale – Elati 230 kV	2027	$218.8	2024	2024HS3, 2024HW	7,283	9,908	G

Project Name	ISD	Capital Cost[12] ($ millions)	Year Study Completed	WECC Base Case Studied	BAA Winter Peak Demand (MW)[13]	BAA Summer Peak Demand (MW)	CPCN[14]
Underground Transmission Line Upgrade							
Kestrel (formerly Project Bronco) Substation (100% customer funded)	2026	$30.9	N/A	N/A	N/A	N/A	G
Poder (Formerly Stock Show) Distribution Substation	2026	$6.1	N/A	N/A	N/A	N/A	NR
Barker Distribution Substation	2027	$100.3	N/A	N/A	N/A	N/A	G
Climax – Robinson Rack – Gilman 115 kV	2029	TBD	2018	N/A	N/A	N/A	NR
Avon-Gilman 115 kV Transmission	2029	TBD	2014	N/A	N/A	N/A	NR
New Conceptual Projects							
Just Transition Solicitation Conceptual Network Upgrades	TBD	TBD	Studies Ongoing	TBD	TBD	TBD	U
New Large Customers Network Upgrades	TBD	TBD	Studies Ongoing	TBD	TBD	TBD	U
New Distribution Substations	TBD	TBD	Studies Ongoing	TBD	TBD	TBD	U
Previously Listed Conceptual Projects							
Central Weld Reliability Loop (formerly Weld-Rosedale-Box Elder – Ennis 230/115kV)	TBD	TBD	Study Ongoing	TBD	TBD	TBD	R
San Luis Valley Reliability Upgrades	TBD	TBD	Study Ongoing	TBD	TBD	TBD	R
Weld County Transmission Expansion	TBD	TBD	TBD	TBD	TBD	TBD	R
Glenwood-Rifle 115 kV Transmission	TBD	TBD	N/A	TBD	TBD	TBD	U
Parachute-Cameo 230 kV #2 Transmission	TBD	TBD	N/A	N/A	N/A	N/A	R
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	TBD	TBD	TBD	R
Northern Colorado Transmission	TBD	TBD	Study Ongoing	TBD	TBD	TBD	R
Gateway South – Craig / Hayden Area Transmission	TBD	TBD	2022	2032HS, 2032HW, 2033LS	7,968	11,405	R

Project Name	ISD	Capital Cost[12] ($ millions)	Year Study Completed	WECC Base Case Studied	BAA Winter Peak Demand (MW)[13]	BAA Summer Peak Demand (MW)	CPCN[14]
Lamar DC Tie Replacement	TBD	TBD	Study Ongoing	N/A	N/A	N/A	U

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

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

a. Projects Completed Since 2024

This section describes the Public Service projects that have been placed in-service since the 2024 Rule 3627 10-Year Transmission Plan.

Colorado's Power Pathway – Segments 2 and 3

As described in more detail below, the Colorado's Power Pathway Project is a 345 kV backbone transmission system planned for eastern Colorado. In May of 2025, Segments 2 and 3 of the Pathway Project, as well as the Canal Crossing, Goose Creek, and May Valley Substations were placed in service. Segments 1, 4, and 5 of the Pathway Project remain under construction.

Northern Colorado Area Plan (formerly Ault-Cloverly 230/115 kV Transmission Project)

The Northern Colorado Area Plan, which has previously been referred to as 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 connect with two new Public Service substations:

- Husky 230/115 kV Substation, which replaces Public Service's Ault 44 kV Substation,
- Collins Street 230/115 kV Substation, which replaced Public Service's Eaton 44 kV Substation.

One objective of the project is to improve reliability by replacing the existing 44 kV system in the area with higher voltage transmission facilities. However, the project also will increase the load-serving and generation resource capability in the area. A CPCN for the project was granted by Decision No. R18-0153 in Proceeding No. 17A-0146E. The project was completed and placed in service in 2024.

Metro Water Recovery Substation (100% customer funded)

This customer-funded project allowed an existing electric service customer to convert from distribution to transmission-level service in order to serve additional demand and includes tapping and looping the existing 115 kV Line 9548 in and out of a new switching station constructed, owned, and operated by Public Service that will serve as the customer's point of interconnection to Public Service's transmission network. The Metro Water Recovery Substation was placed in service in 2025.

Colorado Springs Utilities Unintended Flow Mitigation Project

Public Service and CSU reached mutual agreement on a joint project between the two utilities to resolve the inadvertent power flow issue on the CSU transmission system; consistent with the joint project identified in the CCPG Douglas Elbert El Paso ("DEEP") study as the recommended long-term solution. Under this agreement, CSU took on all engineering and construction responsibility associated with the project, and Public Service contributed funding for the project. Public Service has an ownership share in the new facilities commensurate with its portion of the capital costs associated with construction. More specifically, CSU will (1) install a series reactor at its Flying Horse115 kV substation, and (2) tap CSU's Fuller – Cottonwood 230 kV line via the CSU Briargate Substation and add a 230/115 kV transformer. Public Service had a partial funding responsibility (an up-front capital contribution of approximately $12 million and ongoing O&M responsibility commensurate with its ownership share), while CSU engineered, constructed, operates, and maintains the facilities. The series reactor changes the impedance of the line and reroutes power from congested facilities and may be considered an application of ATT.

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.

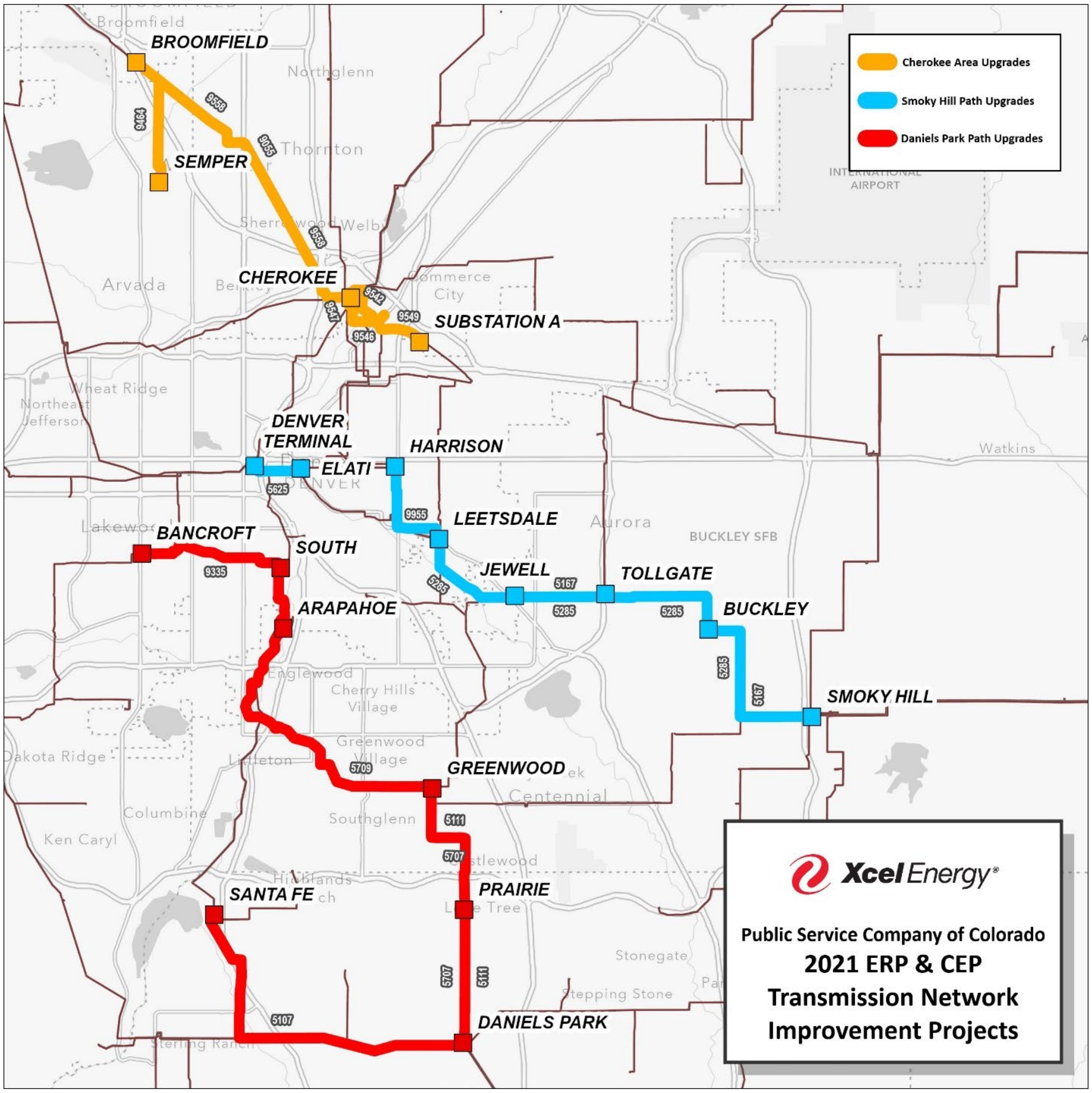
Denver Metro Transmission Network Improvements Project

Through the 2021 ERP & CEP Transmission System Impact Study Report, Public Service's Transmission Planning team has identified a necessary portfolio of Transmission Network Improvement Projects, each geographically targeting one of three critical arteries that feed power into the Denver Metro area: (1) the Daniels Park Path Upgrades, (2) the Smoky Hill Path Upgrades, and (3) the Cherokee Area Upgrades, (collectively, the "Denver Metro Project"). The Denver Metro Project has been designed to reliably address system needs of the Approved Portfolio and is needed to ensure future deliverability of the generation acquired in the 2021 ERP & CEP to Public Service's customers. A CPCN for the Denver Metro Project was granted by Decision No. R26-0001 in Proceeding No. 24A-0560E.

Many complexities exist in the transmission system in the Denver Metro area due to the concentrated amount of load in and around Denver. As increasing amounts of power are imported into the Denver Metro area, versus generated within the Denver Metro area, energy largely moves onto Public Service's higher voltage 230 kilovolt ("kV") system under normal system operations. If there are unplanned outages on the higher voltage system, it can cause flows to shift to underlying interconnected lower voltage system. The interconnectivity of the Denver Metro system increases the reliability and resilience of the transmission system as a whole but also increases the vulnerability of various elements to overloads, thus requiring new solutions and enhancements.

Public Service considered alternative new greenfield transmission facilities to support the 2021 ERP & CEP. While these new transmission facilities would address some of the reliability challenges in delivering the Approved Portfolio to customers in the Denver Metro area, Public Service concluded that it is neither efficient nor effective to develop these types of projects without first maximizing the capabilities of existing transmission facilities and paths. The Denver Metro Project upgrades existing infrastructure. Aside from one limited greenfield substation project and transmission tap line, the Denver Metro Project consists predominantly of upgrades to existing transmission corridors and facilities. The Denver Metro Project consists of upgrades to Public Service's existing 230 kV and 115 kV transmission networks, including approximately 115 circuit-miles of transmission line and 17 substations.

The Daniels Park Path is located in the southern Denver Metro area while the Smoky Hill Path is located in the eastern Denver Metro area. These two paths together share in the principal duty of delivering remote generation into the Denver Metro area. The power flow cases reveal that the Daniels Park and Smoky Hill paths serve considerable load and are highly utilized throughout the various high-renewable dispatch scenarios which occur due to changes in our generation mix. The upgrades along those paths are designed to maximize the existing system's capabilities - first, by removing limiting elements from substations to allow existing transmission facilities to be used to their fullest capabilities, and second, by increasing line ratings through reconductoring or use of alternative technologies. The Cherokee Area Upgrades deliver generation throughout the Denver Metro and serves this dense, high-demand area *via* 115kV and 230kV networks.



The Denver Metro Project addresses challenges in the area to ensure Public Service can continue to provide safe and reliable electric power to its customers. The Approved Portfolio itself cannot do so and meet the State's emission reduction goals without the necessary changes to the transmission system. As the type, scale and location of electric generation sources continues to expand outside the Denver Metro area, the transmission system will experience significant changes in its power flows that Public Service's transmission system – particularly in the Denver Metro area – was not designed to accommodate. Another challenge is the complexity of the transmission system within the Denver Metro area. As power is imported into the Denver Metro area, energy largely moves onto Public Service's higher voltage 230 kilovolt ("kV") system under normal system operations and then moves to numerous interconnected substations and additive transmission lines and then distribution lines at varying voltages. The interconnectivity of the Denver Metro system increases the reliability and resilience of the transmission system as a whole but also increases the vulnerability of various elements to overloads.

Daniels Park Path Upgrades

Daniels Park has been and continues to be one of the main injection points from the 345 kV transmission system in the Denver Metro area. From a Transmission Planning perspective, Daniels Park is also referred to as the southern metro transmission constraint. The Approved Portfolio will significantly increase flows across the southern metro transmission constraint, further exacerbating this constraint on the transmission system.

Daniels Park Substation Upgrades

The Daniels Park Substation is one of the primary import points for the Denver Metro area and with additional flows through this substation if one of the existing 345/230 kV transformers were lost there would be overloads to the remaining transformers. Public Service's analysis indicates that the addition of a fourth 345/230 kV transformer to the Daniels Park Substation would mitigate potential overloads. Energy storage was considered as an alternative, but the system would require an infeasible amount of storage to mitigate the overloads. Phase-shifting transformers were also considered as an alternative, but they were not viable due to the amount of power flowing through the southern metro transmission constraint.

Circuits 5111 and 5707: Daniels Park – Prairie – Greenwood Uprate

This upgrade will involve replacing the conductor on each circuit with a new conductor rated for 2300 amps and associated equipment upgrades at the Daniels Park, Prairie, and Greenwood Substations. These upgrades will address the overloads to these circuits caused by increased generation in the area. Public Service identified 2300 amps as the preferred rating because it prevents a feasible upgrade that can be installed on the existing towers as opposed to rebuilding the segment. Public Service concluded that neither energy storage nor dynamic line ratings were capable to serve as alternatives for this upgrade.

Greenwood Substation Upgrades

This upgrade includes replacing the existing 1215-amp bus tie breaker with a new bus tie breaker rated at 2400 amps due to the increased flows from the south. Public Service evaluated other alternatives, but no alternatives were considered because the overloads can be mitigated through limited scope of directly replacing limiting elements identified within substations.

Circuit 5709: Greenwood – Arapahoe Uprate and Circuit 5717: Greenwood – Monaco Series Reactor

Theses upgrades include installing a power flow controller on the Greenwood to Monaco circuit paired with upgrading the 230 kV Greenwood to Arapahoe Circuit 5709. These upgrades alleviate a range of scenarios in which these transmission paths overload. This includes the need for a series reactor to control power flow and replacing the current conductor rated at 1440 amps with a new conductor rated for 2400 amps. These upgrades were chosen over the alternative of upgrading the existing 230 kV circuits and substations along the Greenwood to Leetsdale path due to this alternative having higher costs and complexity.

Arapahoe Substation Upgrades

One upgrade to the Arapahoe Substation includes replacing the existing 1596-amp bus tie breaker with a new bus tie breaker with a rating of 2000 amps. Another upgrade includes adding a new transformer in the substation to support power flows in southwest Denver as well as additional load growth. This new 230/115 kV transformer will support the 115 kV system in the Denver Metro area by mitigating the overload on the other 230/115 kV transformer currently at the Arapahoe Substation. Other alternatives were considered but were not preferred compared to installing another transformer due to the increased complexity and expected higher cost.

Circuit 9335: Arapahoe – South Tap – Bancroft Uprate

This upgrade includes rebuilding the circuit at a rating of 1200 amps to alleviate overloads between the Arapahoe and South Substations under a variety of dispatch scenarios. Reconductoring this circuit was not deemed viable due to the age and condition of the existing towers. Adding an additional circuit along this path was not preferred because the overloads were mitigated by upgrading the circuit. Other alternatives like energy storage and dynamic line ratings were evaluated but not preferred because the technology was not deemed capable of serving as an alternative for this upgrade.

Circuit 9332: Arapahoe – Air Liquide Tap – South – Gray Street Uprate

The circuit is rated at 600 amps while the conductor on this circuit is rated at 798 amps. The circuit cannot be used to its maximum conductor rating due to the 600-amp switches in the substations. To increase the circuit rating upgrades include replacing the limiting switches in the 115 kV substations along the circuit to allow for the circuit to be operated at full 798-amp rating. Other alternatives were evaluated but none superior to this upgrade due to it being the most cost-effective solution.

South Substation Upgrades

Public Service plans to expand its existing 115 kV South Substation through by using an in and out tap on the 230 kV Arapahoe to Dakota Circuit 5623 and add a 230/115 kV, 280 MVA transformer at the newly expanded South Substation. This single upgrade addresses overloads identified by adding greater power transformation capacity in this part of the Denver Metro area.

Circuit 5107: Daniels Park – Santa Fe

This upgrade includes reconductoring this circuit which will increase its rating from 1214 amps to 1600 amps in order to resolve the overloads to the 230 kV circuit. Public Service anticipates installing an advanced HTLS conductor on the existing towers to meet the recommended rating. ATTs were evaluated but were not found to be a viable option for upgrading this circuit. Additionally, energy storage was considered but not preferred to reconductoring the circuit due to the need for additional land adjacent to the substation, the installation of a complicated switching scheme, and the installation of multiple transformers. The energy storage would also have limited secondary value to the grid as it would only be used for the purpose of mitigating the overload and thus not preferred by Public Service.

Smoky Hill Path Upgrades

Smoky Hill and its neighbor Harvest Mile have been, and continue to be, primary injection points from the 345 kV transmission system into the Denver Metro area. Combined, this location is referred to as the eastern metro transmission constraint. The addition of the Approved Portfolio will significantly increase flows across the eastern metro transmission constraint. Public Service has identified the need to increase the capabilities of the eastern transmission path that move power from outside of the Denver Metro to customers on the other side of the transmission constraint.

Smoky Hill Substation

With additional flows through the Smoky Hill Substation onto the 230 kV system, loss of either of the 345/230 kV transformers at the Smoky Hill Substation results in overloads to the remaining transformer. To mitigate the overloads Public Service identified the addition of a third 345/230 kV transformer to the Smoky Hill Substation as the preferred alternative. Energy storage was considered as an alternative, but an infeasible amount of energy storage would be needed to mitigate the overloads. Additionally, power flow controller devices cannot manage the levels of power flow at the Smoky Hill Substation.

Circuit 5167 and *5285: Smoky Hill – Buckley – Tollgate – Jewell – Leetsdale Circuit 5285*

Due to the increased renewable imports into the Denver Metro area from the Smoky Hill/Harvest Mile area, these circuits experience significant overloads under N1 contingencies. To address these overloads, Public Service's upgrades include replacing the conductor currently installed on each circuit with a new conductor rated for 2000 amps and Public Service anticipates it will install an advanced HTLS conductor on the existing towers to meet the recommended upgrades. Additionally, Public Service's analysis indicates the need to upgrade Circuit 5285 for the entire path from Smoky Hill to Leetsdale and recommends that circuit 5167 be simultaneously upgraded between Buckley Substation and the Leetsdale Tap due to the efficiencies of upgrading both circuits attached to the same towers at the same time and minimizes the need for future rework on circuit 5167. Increasing the voltage of these circuits was evaluated but not preferred due to the extreme costs of this alternative. PST technologies are not capable of reducing flows enough to eliminate the overflows and thus was not preferred. Energy storage and DLR were evaluated but not capable of serving as viable alternatives.

Circuit 5625: Denver Terminal – Elati

During an N-1 outage of the Greenwood – Arapahoe – Denver Terminal circuit, the increased flows on this parallel path can be accommodated by the increased rating planned for Circuit 5283, however, Circuit 5625 from Elati to Denver Terminal experiences overloads based on the rating of the exiting transmission line and substation equipment. Public Service evaluated a range of alternatives to address the overloads on Circuit 5625 and identified that upgrading the circuit to equal the new rating planned for Circuit 5283 from Leetsdale to Elati is the preferred solution to mitigate this overload.

Circuit 9955: *Leetsdale – Harrison*

With increased imports flowing across the 230 kV system toward the center of the Denver Metro area, the 115 kV Leetsdale to Harrison Circuit 9955 experiences overloads across a variety of dispatch scenarios. To address the overloads, Public Service proposes rebuilding this line from its current 708 A rating to 1900 A. Energy storage is not a viable alternative to this upgrade given that limited operation durations are not capable of fully mitigating N-1 overloads. Additional alternatives were considered but all required new greenfield transmission line expansion along with re-configuration of the 115 kV lines in downtown Denver.

<u>Cherokee Area Upgrades</u>

The Cherokee Substation - by virtue of the connected generation located at this substation – plays a key role in supporting the Denver Metro area transmission system by providing counter flow to the eastern and southern Denver Metro constraints. To fully maximize the proposed upgrades identified in this study, and to mitigate additional overloads caused by the change in the system generation portfolio, Public Service has identified the following system improvements around in and around Cherokee.

New Substation A

There are a variety of N-1 outages on lines and transformers around Cherokee that occur under different dispatch scenarios. After consideration for multiple alternatives to the Cherokee bus-tie, a greenfield solution was chosen. This includes the addition of a new 115 kV switching station approximately two miles southeast of the existing Cherokee substation which will include in and out taps of lines 9542, 9546, and 9549. The other alternatives not selected would either not fully mitigate the overloads or were significantly larger and more complex than the chosen alternative.

New Transmission Line Cherokee – New Substation A

To mitigate overloads on the transmission paths in and out of the Cherokee Substation, Public Service will need to add a two-mile new 1600 A rated 115 kV transmission line between the new 115 kV Substation A and Cherokee. Other alternatives were evaluated but were eliminated as they were more expansive and less beneficial than the chosen alternative.

Circuit 9542: Cherokee – New Substation A

This upgrade includes uprating the line between the Cherokee Substation and the new 115 kV New Substation A from 770 A to 1600 A making the new rating sufficient for the system under multiple N-1 contingencies to move power between the Cherokee North and South buses, thus mitigating overloading other elements in the system. Public Service considered other alternatives but they all would require new greenfield transmission lines and additional re-configuration of the downtown 115 kV lines.

Circuit 9546: Cherokee – Mapleton – New Substation A

This upgrade includes uprating the line between Cherokee to Mapleton and the new 115 kV switching station from 799 A to 1600 A making the new rating sufficient for the system under multiple N-1 contingencies to move power between the Cherokee North and South buses, thus mitigating other overloads on the system. Public Service considered other alternatives, but they would have required new greenfield transmission lines and additional re-configuration of the downtown 115 kV lines.

Circuit 9549: Cherokee – Conoco – New Substation A

This upgrade includes uprating the line between the new 115 kV switching station and the Conoco South from 799 amps to 1600 amps making the new rating sufficient for the system under multiple N-1 contingencies to move power between the Cherokee North and South buses, thus mitigating other overloads on the other elements of the system. Public Service considered other alternatives, but they would have required new greenfield transmission lines and additional re-configuration of the downtown 115 kV lines.

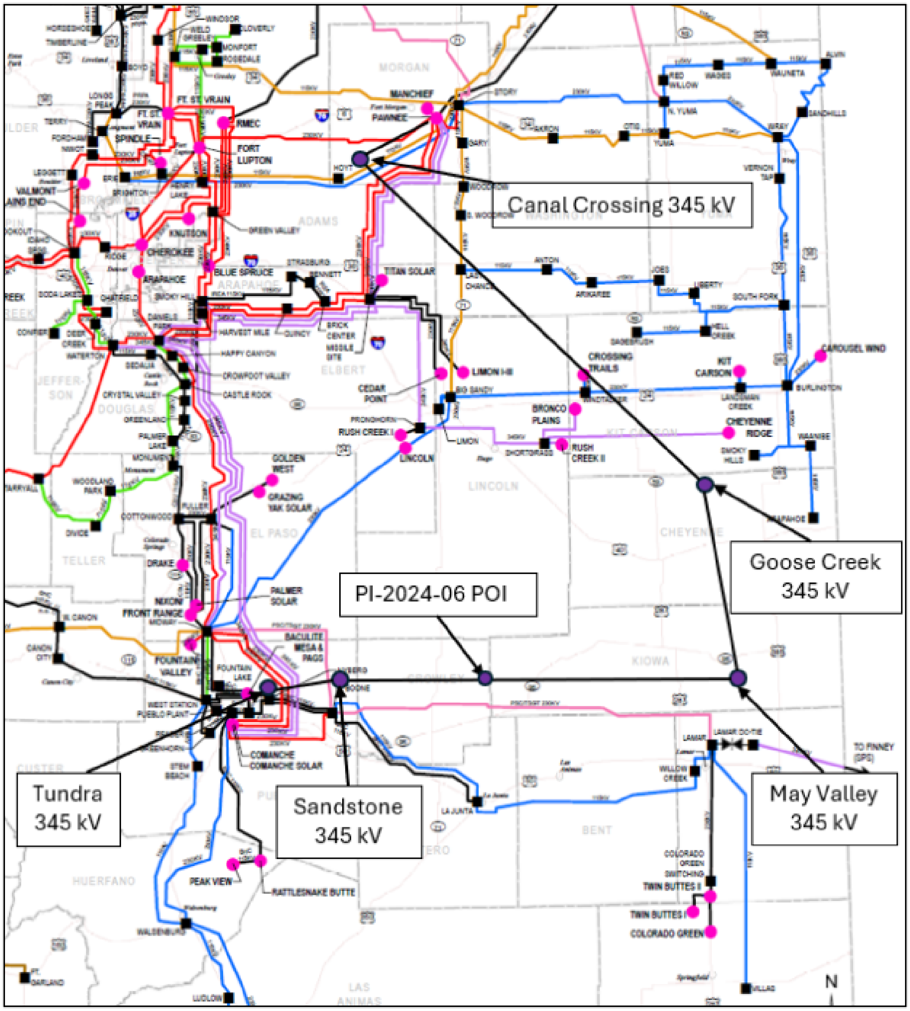
Circuits 9055, 9558, and 9464: Cherokee – Federal Heights – Semper – Broomfield

The prevailing flows on this path run from Valmont to Cherokee, but with the addition of the Approved Portfolio the direction of the flow changes to now flow out from Cherokee in a northern direction. Under this change, an N-1 outage of either circuit will overload the other. To mitigate this overload, Public Service identified the need to rebuild these circuits to a rating of 2000 amps. Other alternatives were considered but would require new greenfield transmission lines.

PI-2024-06 Generation Interconnection Substation

A generation developer has entered into a Provisional Large Generator Interconnection Agreement ("PLGIA") with Public Service to obtain interconnection to Public Service's transmission system. The interconnection request, which was studied as PI-2024-6, requires Public Service to construct a new 345 kV switching station in Crowley County, Colorado that taps one circuit of Segment 4 of the Pathway Project between the May

Valley and Sandstone Switching Stations. Consistent with the terms of the PLGIA, the new switching station is expected to be placed in service in 2028.



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

5283 Leetsdale – Elati 230 kV Underground Transmission Line Upgrade

The underground Leetsdale – Monroe – Elati 230 kV transmission line (Circuit 5283) was derated in 2022 based on a facility rating update study for the circuit. Because of the substantial derate (>20%), 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 Cherokee 4.

A transmission project is planned to mitigate existing, as well as expected future, transmission congestion challenges. Public Service's analysis has identified that upgrading the existing oil-filled cable used on this circuit with a new cross-linked polyethylene ("XLPE") 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 be required to be constructed underground. Public Service conducted detailed evaluations of the suitability of ATTs and NWAs for this project as alternatives to the construction of a replacement transmission line but did not identify viable alternatives to the planned upgrade. Public Service's application for a CPCN for this project is pending before the Commission in Proceeding No. 24A-0560E.

Colorado's Power Pathway

Colorado's Power Pathway is a 345 kV transmission project planned as a means to deliver an estimated 3000-3500 MW of simultaneous power output from new renewable energy resources located in eastern and southern Colorado. The primary driver for Public Service is to meet 80 percent carbon reduction from 2005 carbon levels by 2030 consistent with the State's statutory Clean Energy Plan mandate. The project was identified within the CCPG 80x30 Task Force. The project consists of approximately 560 miles of double circuit 345 kV lines for providing transmission access to Energy Resource Zones (ERZs) 1, 2, 3, and 5, and connecting them to the Denver Metro area. The project includes the following transmission facilities:

- Expansions of the Fort St. Vrain, Pawnee, Tundra, and Harvest Mile Substations
- A new Canal Crossing Switching Station near the Pawnee Substation
- A new Goose Creek Switching Station near the Cheyenne Ridge Wind Project

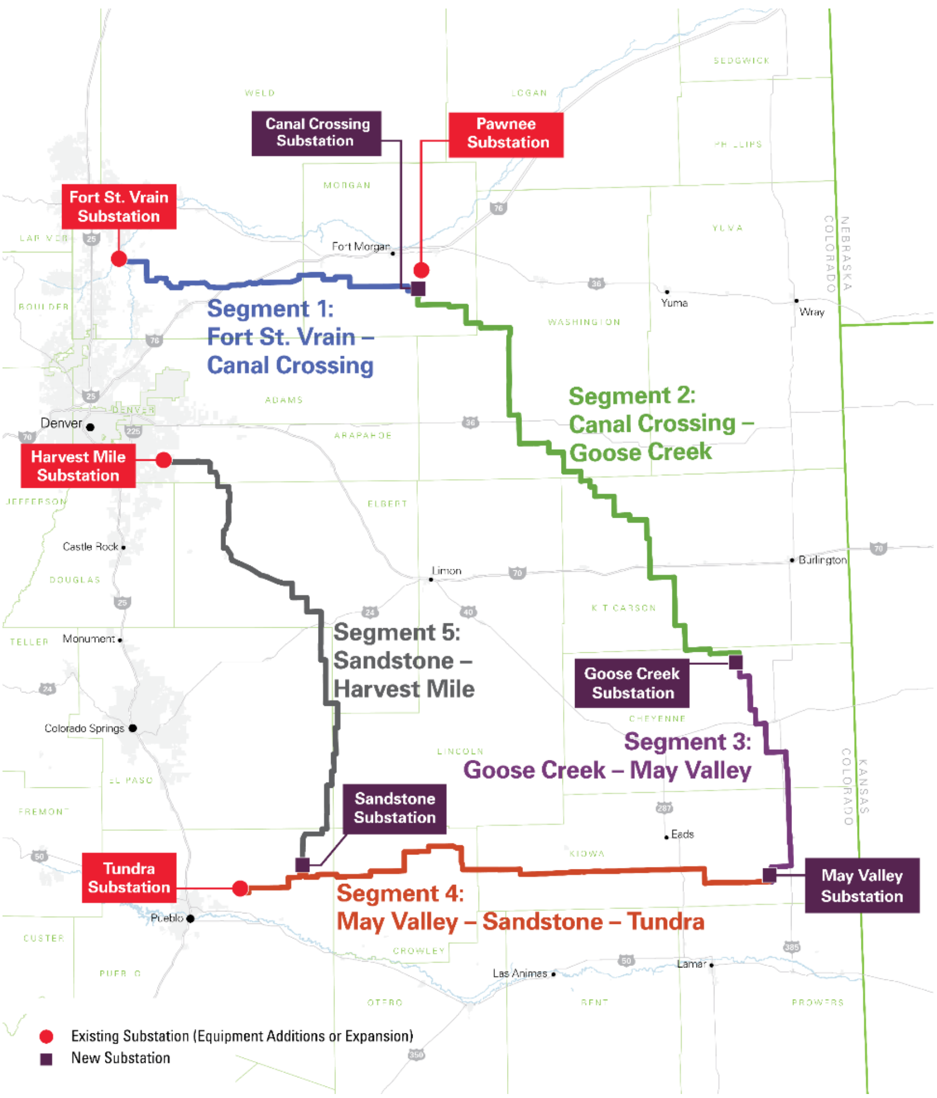
- A new May Valley Switching Station near the Lamar Substation
- A new Sandstone Switching Station in Pueblo County, which was added to the Pathway Project primarily as a result of space constraints identified at the Tundra Switching Station.
- Segment 1: 345 kV double-circuit transmission line between Fort St. Vrain and Canal Crossing
- 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, Sandstone, and Tundra
- Segment 5: 345 kV double-circuit transmission line between Sandstone and Harvest Mile

A CPCN for the Pathway Project was approved by the Commission in Proceeding No. 21A-0096E, and a CPCN for the addition of the Sandstone Switching Station to the scope of the Pathway Project was approved in Proceeding No. 24A-0131E.

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 $1.7 billion and in-service dates for the segments ranging from 2025 to 2027. The Pathway Project is currently under construction, and as noted above Segments 2 and 3 were placed in service in May 2025. Public Service files semi-annual progress reports in Proceeding No. 21A-0096E.



Colorado's Power Pathway – May Valley – Longhorn Extension

The Pathway 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 has granted a conditional CPCN for the May Valley-Longhorn Extension in Proceeding No. 21A-0096E. A decision on whether these facilities will be constructed will be made in Public Service's JTS Proceeding.

Pathway Voltage Control / Reactive Support and Grid Strengthening

Public Service has identified voltage control/reactive support and grid strengthening facilities which are needed to support the safe and reliable operation of the Colorado's Power Pathway Transmission Project under the generation portfolio approved as part of Public Service's 2021 ERP & CEP. The planned project involves the installation of one Static Synchronous Compensator ("STATCOM") at the Goose Creek Substation and the installation of one Synchronous Condenser ("SynCon") at the May Valley Substation. These facilities are needed to improve the resilience of the transmission system, reduce the risk of line and generation outages that may result from system disturbances, and permit the Pathway Project to perform to its full intended capacity within required operating and reliability limits. Public Service plans that the facilities will be fully in service by January 2027. Public Service's application for a CPCN for these facilities is pending before the Commission in Proceeding No. 25A-0409E.

Barker Distribution Substation

The Barker Substation is needed to address reliability concerns and serve growing demand on the transmission network servicing downtown Denver and the non-network load in the surrounding area. This project consists of a new Gas Insulated Substation ("GIS") including two new 50 MVA, 230/13.8 kV distribution transformers and associated switchgear and feeders. The project's scope includes the construction of the transmission substation and approximately 2700 feet of double circuit underground 230 kV cross-linked polyethylene (“XPLE”) transmission line. A CPCN was granted for the Barker Distribution Substation in Proceeding No. 25A-0069E.

Poder Distribution Substation

This project consists of constructing the new Poder distribution substation in Denver. The Poder Substation, which has previously been identified in Public Service’s previous reporting as DCP Stock Show, includes the installation of a 115/13.8 kV, 50 MVA distribution transformer. The new substation will be located near the National Western Complex and is needed to provide additional capacity for load growth and redundancy in the area. The transmission portion of this project consists of extending a 115 kV transmission line to the new substation site and installing the substation transmission facilities required to supply power to the new 115/13.8 kV, 50 MVA distribution transformer and associated equipment. The Commission determined that a CPCN is not required for the Poder Distribution Substation by Decision No. C18-0843 in Proceeding No. 18M-0005E.

Kestrel Substation

This customer-funded project will create a transmission interconnection for a data center campus located in Aurora, Adams County, Colorado. This project has also been referred to as Project Bronco or the QTS Transmission Facilities in other Public Service filings. The project consists of approximately 1.4 miles of double circuit 230 kV transmission line from the midpoint of an existing 230 kV Circuit 5185, which currently terminates at the Spruce and Chambers substations. Public Service will also construct a new 230 kV transmission switching station, which will be located adjacent to the customer’s substation. A CPCN was granted for the Kestrel Substation in Proceeding No. 23A-0330E.

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 2029, 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

Just Transition Solicitation Transmission Network Upgrades

<u>*Just Transition Solicitation Phase II Transmission Planning Process*</u>

Public Service filed its Just Transition Solicitation ("JTS") resource plan in October 2024 in Proceeding No. 24A-0442E. As approved by the Commission in the JTS Phase I Decision, Decision No. C25-0747, Public Service will engage in a "two-step" transmission planning process associated with the Phase II JTS resource solicitation. As agreed to in the JTS proceeding, Public Service should make JTS Transmission Portfolio CPCN filings in late 2026 and mid-2027, consisting of proactive proposals to facilitate the JTS Supplemental RFP and portfolio implementation projects from the JTS Base RFP, however, the timing interaction of the NTP process and ongoing transmission study efforts may affect these timelines.

Public Service has commenced a small-group stakeholder process with Commission Staff, the Office of the Utility Consumer Advocate, and the Colorado Energy Office to inform near-term and future transmission planning and explore and implement revised transmission modeling to be implemented as part of the Phase II modeling. This stakeholder group will investigate and analyze the drivers and benefits of major deliverability and proactive transmission investments. In addition to informing the JTS Base and JTS Supplemental Phase II modeling, this small-group stakeholder process will also specifically inform the JTS Transmission Portfolio CPCN filings consisting of two types of projects: (1) deliverability/reliability projects; and (2) proactive projects. Deliverability/reliability projects will go through Public Service's approved FERC 890 process; whereas, proactive projects will go through the CCPG process.

With respect to deliverability/reliability projects necessary to implement the approved portfolio from the JTS Base RFP, it would follow the following process: (a) the provision of up to four reliability and deliverability analyses as part of Public Service's 120-Day Report; (b) Commission provision of Phase II feedback on transmission on four preliminary reliability and deliverability analyses; and (c) re-engagement of interested stakeholders through the FERC 890 Planning Process leading up to the JTS Implementation Phase Transmission Portfolio CPCN filing.

With respect to proactive projects, Public Service's Proactive Proposal process commenced through the creation of the CCPG JTS Task Force to evaluate new transmission needs. The CCPG JTS Task Force approve a study scope in October 2025 and the study work is currently underway.

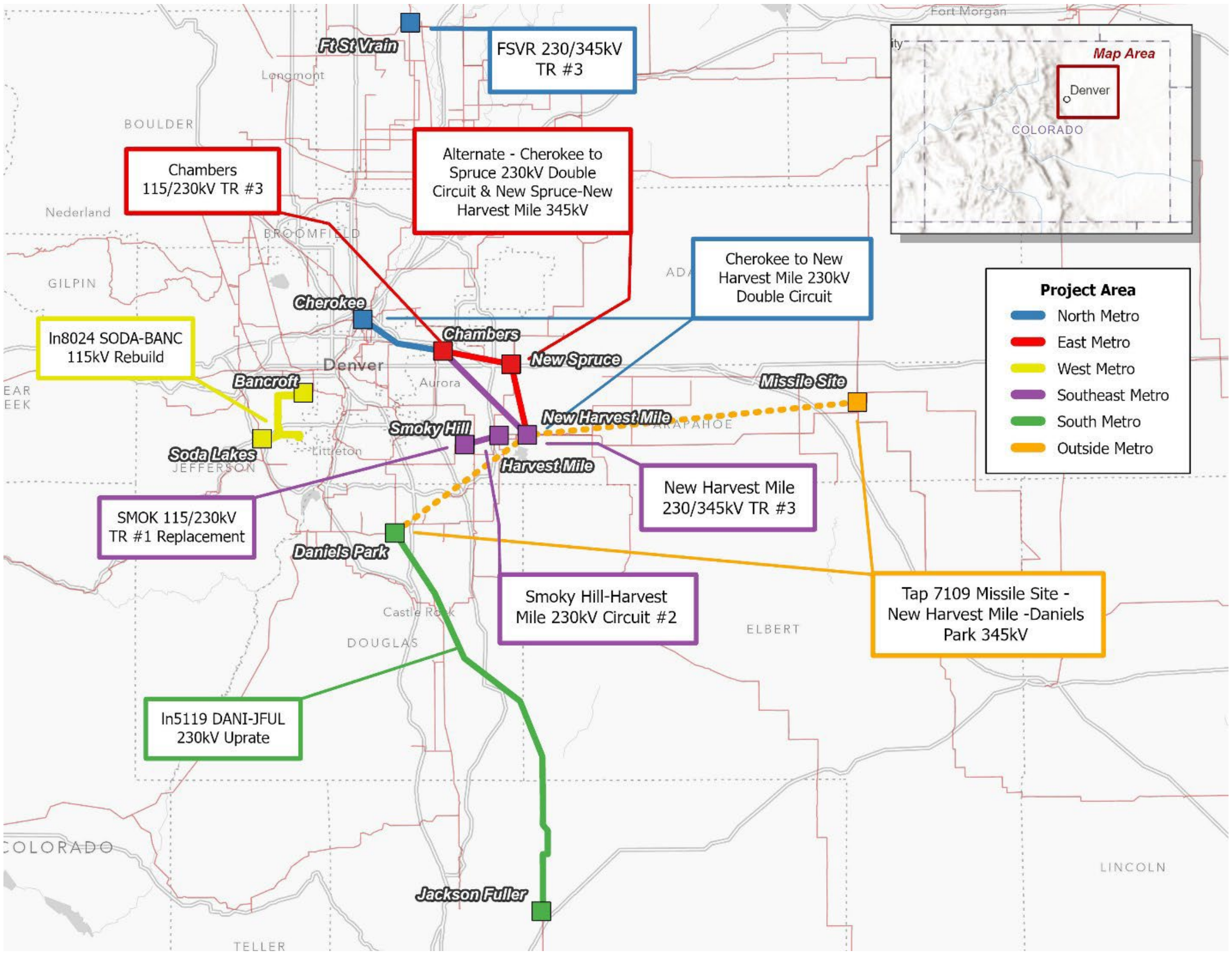
JTS Phase I Transmission Analysis and Conceptual Projects

As part of Phase I of the JTS Proceeding, Public Service conducted additional analysis of potential transmission needs associated with a variety of hypothetical resource portfolios and load forecasts. Public Service conducted two transmission studies within Phase I of the JTS: the JTS Transmission Study and the JTS Alternative Solution Study. The purpose of the JTS Transmission Study was to: (1) specifically identify the potential stress to the transmission system under four hypothetical JTS Resource Portfolios; under two load forecast assumptions; and, (2) where applicable, provide guidance on identifying transmission improvements that may be needed to ensure the reliable delivery to Public Service's system under varying conditions. The purpose of the JTS Alternative Solution Study was to evaluate additional alternatives to one of the projects initially identified in the JTS Transmission Study. Study reports for each of the JTS transmission studies are filed in proceeding No. 24A-0442E.

The projects identified through the JTS Transmission Study and JTS Alternative Solution Study are currently conceptual in nature, as the final outcome of resource acquisitions in the Near-Term Procurement in Proceeding No. 21A-0141E and the JTS Phase II resource solicitation, as well as the results of the two-step transmission planning process discussed above, will affect the identification of transmission system needs.

JTS Transmission Study Conceptual Projects

The following projects were identified as needed under at least one of the scenarios evaluated in the JTS Transmission Study, however, not all projects were needed in each scenario.



Project	Description
Smoky Hill – Harvest Mile 230 kV Circuit #2	This project would include building a second 230 kV circuit between Harvest Mile and Smoky Hill substations. This project would improve system reliability by eliminating a potential single contingency failure between these substations.
Ft. St. Vrain 230/345 kV TR #3	This project involves adding a third 230/345 kV autotransformer at the Ft. St. Vrain Substation and would improve system reliability for power delivered by the Pathway Project at the Ft. St. Vrain substation.
New Double Circuit 230 kV Line from New Harvest Mile	This project involves installing a new double-circuit 230 kV line from Harvest Mile to Chambers to Sandown to Cherokee. The 2021 ERP & CEP 120-Day Study indicated that these circuits

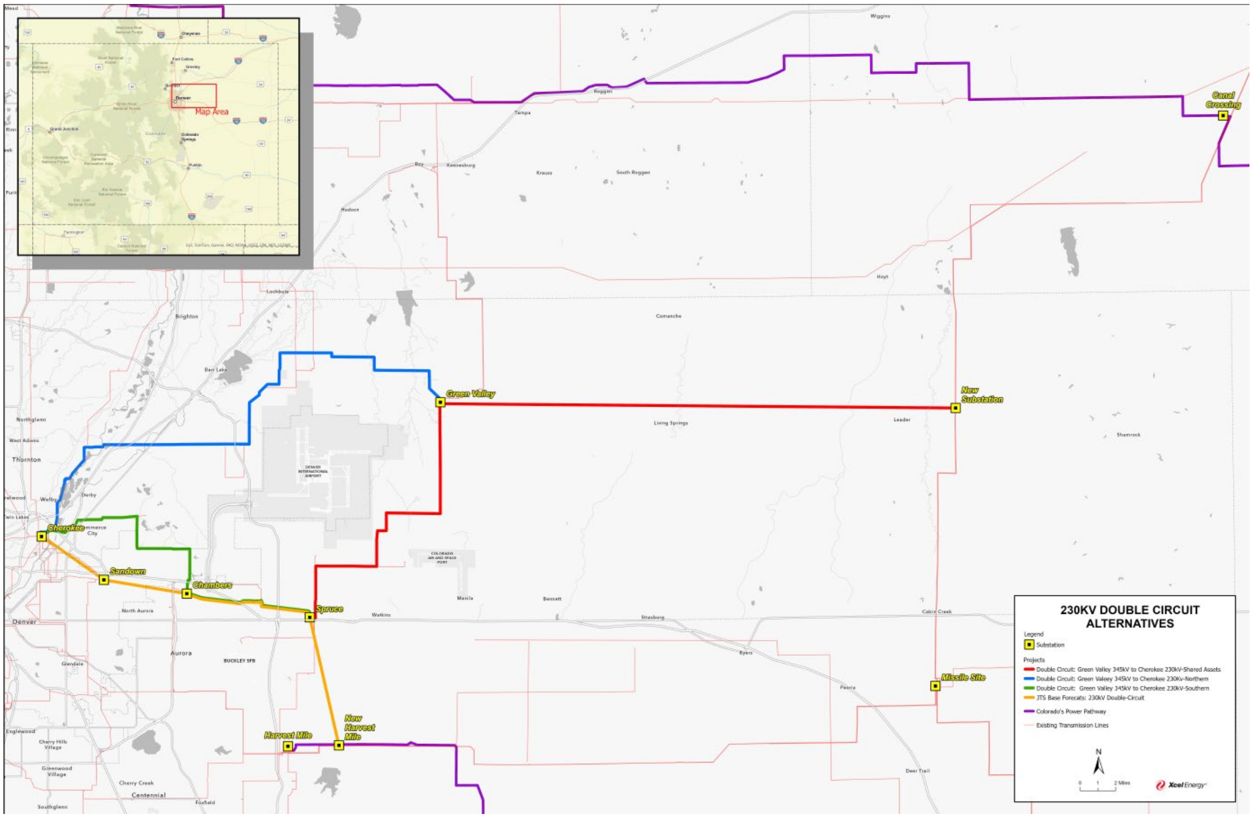
345 kV to Cherokee 230 kV ("230 kV Underground Double Circuit")	should be constructed as 345 kV capable. The project includes installing two 560 MVA 230/345 kV transformers at Harvest Mile, along with ~28 miles of new, double circuit transmission line. This project would consist of ~20 miles of underground transmission, and ~8 miles of overhead transmission. For the substations, Public Service assumed an expansion/new location will be required at the Harvest Mile substation to fit the 230 kV connections. As discussed for the Chambers 3rd 115/230kV TR 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 assumed that a new substation will be required near Sandown for the 230 kV connection. At Cherokee substation there is space within the existing yard to build out the facilities required to connect the new lines.
230 kV Underground Double Circuit Alternate – New Harvest Mile to Spruce 345 kV to Cherokee 230 kV	This project would involve installing a new double-circuit 345 kV line from Harvest Mile to Spruce Substation and installing a new double-circuit 230 kV line from Spruce to Chambers to Sandown to Cherokee. The project will include four 560 MVA 230/345 kV transformers at Spruce. Public Service already contemplated these circuits should be constructed as 345 kV capable in the New Double Circuit 230 kV Line project. This alternative project would operate the eastern terminal of the project at 345 kV between Harvest Mile and Spruce. Public Service assumed the same alignment at ~28 miles long. For the substations Public Service assumed an expansion/new location will be needed at Spruce to fit the 345 kV and 230 kV connections. As discussed in the New Double Circuit 230 kV Line project, a new substation near Harvest Mile is already contemplated and is also required for this project. Public Service contemplated the remainer of the

	project configuration in the New Double Circuit 230 kV Line project.
Tap In7109 Missile Site – Daniels Park 345 kV in-and-out of a New Harvest Mile 345 kV	This project involves uprating limiting elements on the existing In7109 Missile Site to Daniel's Park 345 kV line, and would add a 345 kV connection in-and-out of Harvest Mile. This project will improve system reliability by transferring some of the power delivered at Daniel's Park into the New Double Circuit 230 kV project, independent of which configuration is selected. Public Service assumes this project is only built when the system configuration includes the New Double Circuit 230 kV Line project. For substations, as discussed in the New Double Circuit 230 kV Line project, a new substation near Harvest Mile is already contemplated and is also required for this project.
New Harvest Mile 230/345 kV TR #3	This project will improve capability of power delivery when tapping In7109 in-and-out of a New Harves Mile 345 kV by installing a third 230/345 kV autotransformer. Public Service assumes this project is only built when the system configuration includes the Tap In7109 Missile Site-Daniels Park 345 kV project, and the New Double Circuit 230 kV Line project, which includes two 230/345 kV autotransformers.
Chambers 115/230 kV TR #3	This project involves installing a third 280 MVA 115/230 kV transformer at the Chambers Substation. As there is no room to complete this project at the existing Chambers Substation, the project assumes construction of a new substation near the Chambers Substation.
Circuit 8024 Soda Lakes – Bancroft 115 kV Rebuild	This project includes rebuilding Public Service's Circuit 8024 Soda Lakes to Allison to Kendrick to Bancroft 115 kV line. This project will improve system reliability due to expected load growth.

Circuit 5119 Daniels Park – Jackson Fuller 230 kV Uprate	This project involves uprating the limiting elements on Public Service's Circuit 5119 Daniels Park to Jackson Fuller 230 kV line. This project will improve system reliability and capability for power delivered from the south.
Smoky Hill 115/230 kV TR #2 Replacement	This project will increase the Smoky Hill 115/230 kV transformer rating to enhance our ability to deliver more capacity at Smoky Hill.

JTS Alternative Solution Study Projects

In addition to the projects initially identified in the JTS Transmission Study, Public Service also further evaluated additional alternatives to the 230 kV Underground Double Circuit and the alternative Cherokee to Spruce 230 kV Double Circuit and New Spruce to New Harvest Mile 345 kV projects. Through this additional analysis, Public Service identified two further alternatives to the New Harvest Mile to Cherokee alternatives: a "Northern Option" and a "Southern Option" of a Double Circuit Green Valley 345 kV to Cherokee 230 kV Project. Both the Northern Option and Southern Option include a new 345 kV double circuit line from a new substation located on the Canal Crossing – Missile Site 345 kV line to the Green Valley Substation and a new 345 kV double circuit line from the Green Valley Substation to a new 345 kV Spruce Substation. The Northern Option includes a new 230 kV double circuit path from Green Valley to Cherokee on the northern side of the Denver Metro area, whereas the Southern Option includes a new 230 kV double circuit from Spruce to Chambers to Cherokee.



Large Customer Interconnection Requests

Public Service has received significant interest from current and prospective customers seeking to construct new or expanded energy-intensive facilities in its service territory. Such requests could substantially increase load and peak demand on Public Service's system and would require significant expansion of the transmission system to accommodate the demand. Customers are primarily seeking to take service at transmission-level voltages, and individual customer requests may require the construction of transmission line extensions to connect customers' facilities to the transmission system as well as network reinforcements to ensure that adequate transmission capacity is available to provide the requested service. Public Service notes that customer requests have varying levels of confidence in the customer's intent to move forward with obtaining service from Public Service, and the level of customer commitment will control how Public Service plans for and proposes transmission system expansions.

At this time, Public Service has two primary ongoing study efforts associated with large customer interconnection requests: (1) studies of specific customer interconnection requests, including a cluster study of customers whose requests are concentrated in an area referred to as “Data Center Row” near Denver International Airport, and (2) scenario-based studies of broader system expansion needs associated with serving large customer requests to identify as directed by the Commission in Decision No. C25-0747, referred to as the “Large Load Tariff Transmission Study.”

Based on the status of ongoing study efforts, Public Service has not yet completed its evaluation of specific transmission facilities that are necessary to serve large customer interconnection requests. The scope, cost, and in-service dates of any transmission associated with customer requests are still uncertain, and as such does not include any conceptual projects associated with large customer loads in this 10-Year Transmission Plan. Public Service will be filing a Large Load Tariff with the Commission as required by Decision No. C25-0747 in the JTS proceeding that will, among other issues, address transmission system expansions necessitated by new or expanded large customer loads in excess of 20 MW and include the Large Load Tariff Transmission Study.

Distribution Substations

Through its Distribution System Planning (“DSP”) process, Public Service has identified new greenfield distribution substations that are necessary to accommodate growing customer demand. Public Service’s most recent DSP was filed in 24A-0547E. The following greenfield distribution substation projects were identified in Public Service’s DSP, and are currently under evaluation to identify specific transmission facilities associated with each substation.

Substation	Approximate Location
Gray Street Distribution Substation	Lakewood
Dove Valley Distribution Substation	Arapahoe County
Superior Distribution Substation	Superior
Engelmann Spruce Distribution Substation	Adams County
Berkley Distribution Substation	Adams County/Jefferson County
Lowry Distribution Substation	Denver/Arapahoe County

North Sheridan Distribution Substation	Denver
Cherry Knolls Distribution Substation	Arapahoe County/Denver
Columbine Valley Distribution Substation	Arapahoe County
Welby Distribution Substation	Denver
Cherry Creek Distribution Substation	Denver
Lucerne Distribution Substation	Weld County
Wellington Distribution Substation	Wellington
Wilson Ranch Distribution Substation	Fort Collins
Central Park Boulevard Distribution Substation	Denver
Ball Arena Distribution Substation	Denver
River Mile Distribution Substation	Denver
Leyden Distribution Substation	Jefferson County
Sampson Gulch Distribution Substation	Arapahoe County
Daniels Park Distribution Substation	Douglas County
Denver International Airport (DEN) South	Denver
Denver International Airport (DEN) North	Denver
Antonito Distribution Substation	Antonito

ii. Previously Reported Conceptual Transmission Projects

Central Weld Reliability Loop (Formerly Weld–Rosedale–Box Elder–Ennis Transmission)

Upgrades that replace the 44 kV transmission network that serves customers in Weld County remain a priority for Public Service. Public Service has been evaluating system improvements in Weld County for several years and is currently working with the CCPG Foothills Subcommittee to validate transmission alternatives for the area south of Greeley. Public Service's 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 generation resource development. Public Service is also seeking to design a transmission project that will align with other planned transmission projects in the area, including the recently-completed Northern Colorado Area Plan Project. Based on preliminary study results, Public Service is evaluating a 230 kV line from Weld to Rosedale and a 230 kV or 115 kV line from Rosedale to Box Elder to Ennis in order to meet the stated objectives. Completion of coordinated study results through CCPG is necessary to identify the preferred alternative, and Public Service will identify a planned transmission project at that time.

San Luis Valley Reliability Upgrades

Public Service, working with the CCPG SLV Subcommittee, is evaluating potential transmission network upgrade projects located in the San Luis Valley. In its 2024 Rule 3627 Ten-Year Transmission Plan, Public Service identified several conceptual transmission projects located in the San Luis Valley that were driven by transmission plans associated with Public Service's Preferred Portfolio in the 2021 ERP & CEP:

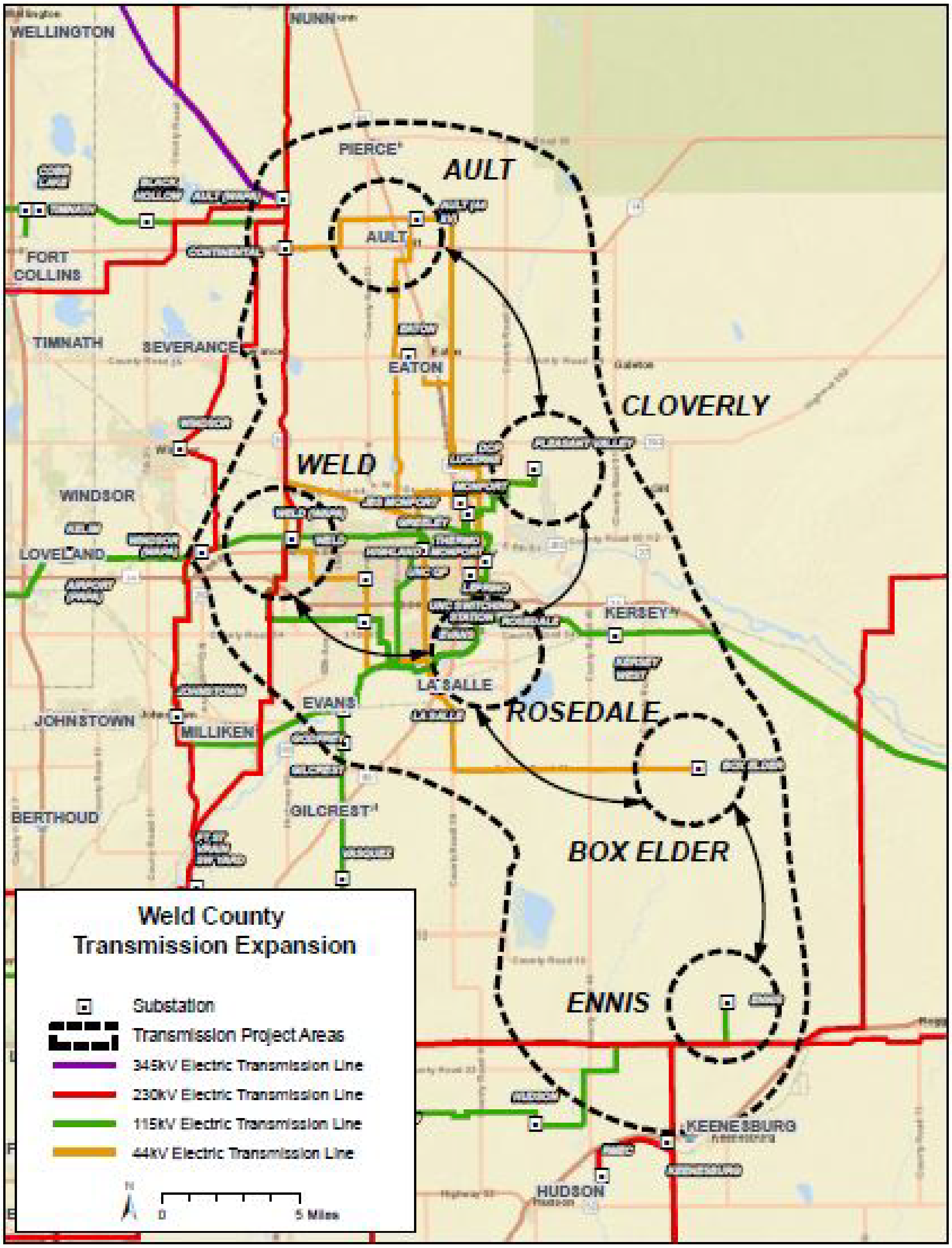
- Uprate Substations on Circuit 9811 Poncha Junction and San Luis Valley
- Uprate Substations on Circuit 3006 Poncha West and San Luis Valley
- Malta to Poncha Junction Circuit 9255 Uprate
- San Luis Valley 115 kV Circuit 9431 Uprate
- Alamosa to Mosca to San Luis Valley 69 kV Circuits 6935/6936 Uprate
- New 115 kV Line San Luis Valley to Alamosa Terminal

While generation bid failures in the San Luis Valley have resulted in the need for some of these projects no longer being driven by the 2021 ERP & CEP, Public Service is continuing to evaluate transmission system upgrades within the San Luis Valley to achieve greater reliability and address planned generation retirements. Retirement of the existing CTs in the San Luis Valley has been extended to 2030 due to failed bids. Public Service expects that some elements of the transmission upgrades that had previously been identified through studies in Phase II of the 2021 ERP & CEP may be re-identified as planned projects to address reliability and future capacity expansion needs, despite their need no longer being driven specifically by the resource portfolio acquired in the 2021 ERP & CEP. Public Service anticipates identifying planned transmission upgrades in the San Luis Valley following the conclusion of its coordinated planning efforts.

Weld County Transmission Expansion

This conceptual project would allow interconnection of new resources and complement other transmission plans in Northeast Colorado such as the Northern Colorado Area Plan

Project and the Central Weld Reliability Loop Project. This expansion project may be considered as a third or eastern phase of the planning efforts that have been undertaken to modernize the transmission system in Weld County. In general, the Weld County Expansion conceptualizes an increase in transmission capability between the recently completed Northern Colorado Area Plan Project, the conceptual Central Weld Reliability Loop project, and the northern Denver metro area. This transmission expansion could enable an increase in north to south transfers into Denver metro 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 and reliability.

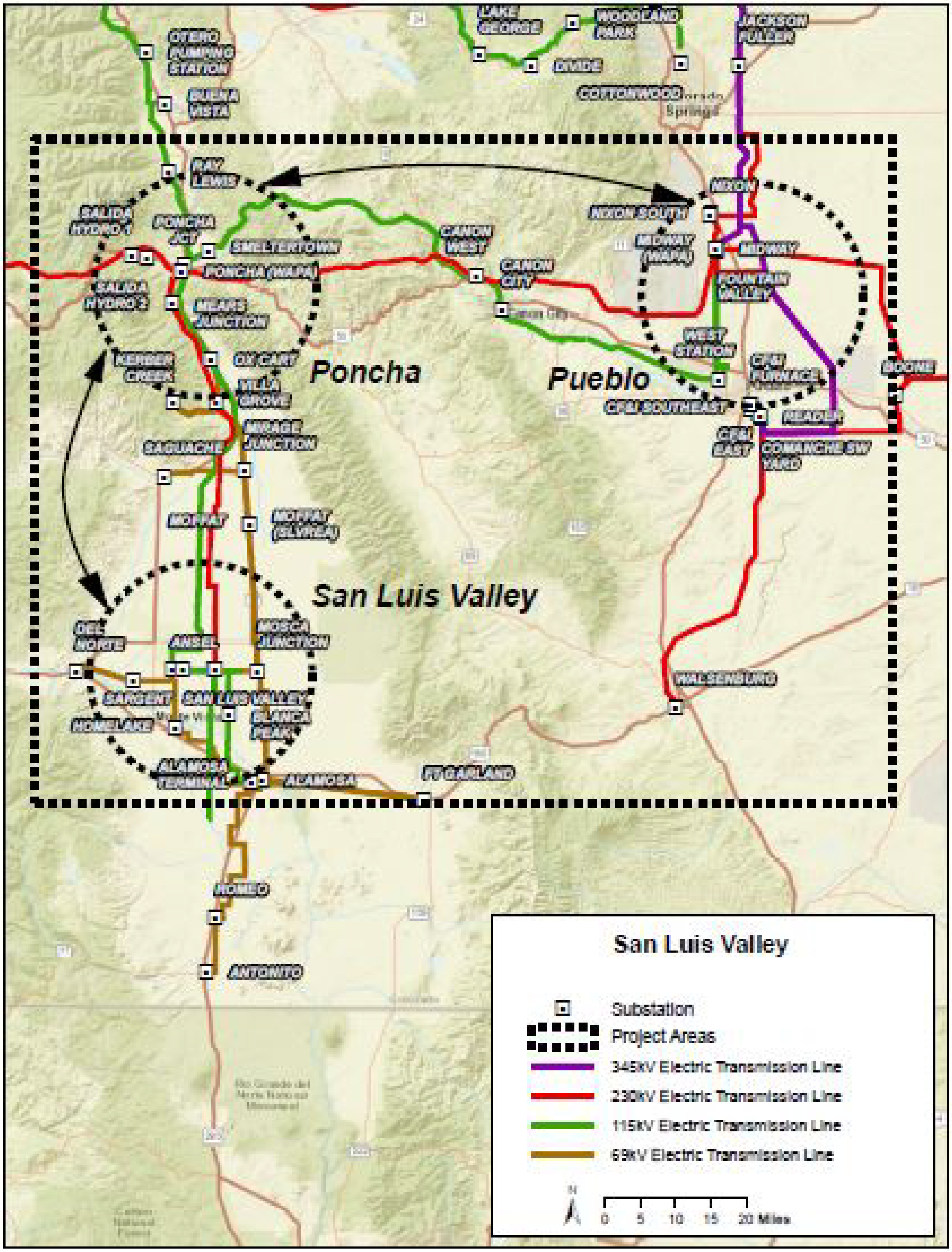
A separate project exists to address the condition of the assets due to this line crossing the Wildfire Risk Zone.

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 also recognizes that new high-voltage transmission into the San Luis Valley would help improve electric system reliability and customer load-serving capability and accommodate development of additional renewable generation resources. Past studies by the CCPG San Luis Valley Task Force ("SLVTF") indicated that a new 230 kV transmission line from the San Luis Valley Substation to Poncha Substation would be a first step to accomplish the reliability objectives. Additional transmission beyond Poncha to the Front Range 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 will initiate an effort to update past studies and refresh the transmission alternatives in the area.


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

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 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 performed the "Gateway South-Northwest Colorado 500 kV Interconnection Project - Interconnection Reliability Study" in 2022. The purpose of the study was to assess the reliability impact of the construction of an 80-mile 500 kV transmission line between Hayden Substation and a new "Little Snake Substation" on the Aeolis-Clover 500 kV transmission line. The study also considered the reliability impact of the construction of a 65-mile 500 kV transmission line between the Craig Substation and the "Little Snake Substation." The study attempted to understand how generation dispatch between the Public Service area in Eastern Colorado and the PACE area in Wyoming impacts the amount of flow possible on these two alternative lines.

Lamar DC Tie Upgrade

The Lamar HVDC back-to-back converter station is a 210MW 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 anticipates that this project would be studied with input from the CCPG subregional planning area and the adjacent Southwest Power Pool regional planning area.

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 8. Colorado Springs Utilities Projects

In-Service	Project Name	Description	Purpose
2026	Nixon-Kelker 230 kV Line Uprate	Increase clearance on Nixon-Kelker 230 kV line to increase facility rating on the line.	Increase facility rating
2028	South System Improvements	Midway-Kelker 230kV Transmission Line	New transmission line - reliability
2027	Central System Improvements	New Kelker-South Plant 115kV Line Rebuild Kelker Substation to Full Breaker and a Half (230 and 115kV)	Reliability
2024	Flying Horse Flow Mitigation	Install Series Reactor on Flying Horse-Monument 115kV Line Section to Mitigate Inadvertent Power Flows	Reliability

In-Service	Project Name	Description	Purpose
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
2024	Kettle Creek Transformer	Kettle Creek 115/12.5kV Power Transformer Addition	Load serving
2029	Flying Horse Transformer	Flying Horse 115/12.5kV Power Transformer Addition	Load serving
2026	Claremont Transformer	Claremont 230/34.5kV Power Transformer Addition	Load serving
2025	Fuller BESS	100 MW Battery Energy Storage Project Interconnection – Fuller Creek Substation	Interconnection – Energy Storage PPA
2026	Horizon Transformer	Horizon 230/34.5kV Power Transformer Addition	Load serving

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 9. Platte River Power Authority Projects

In-Service	Project Name	Description	Purpose
2026	Black Hollow Solar Phase 2 Project	Phase 2 of solar power plant added at Severance substation.	Renewable Generation
2026	Weld Battery Energy Storage System Project	100 MW, 4-hour duration battery energy storage	System Reliability

		system added at Severance substation.	
2028	Rawhide Aeroderivative Turbine Project	Five gas aeroderivative turbines added at Rawhide substation and associated bus expansion.	Dispatchable Generation

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 10. Western Area Power Authority Projects

In-Service	Project Name	Description	Purpose
2028	Weld Transformer Replacement Project	Replace the transformer at Weld due to condition/age.	Replace aging equipment and increasing area reliability
2029	Blue Mesa Reactor and Transformer Project	Install a new reactor and transformer at Blue Mesa substation due to increase area voltage support.	Reliability
2030	Fort Morgan Capacitor Bank Replacement Project	Replace existing 15MVAR cap bank with larger 15/30/45 MVAR bank to provide additional area voltage support.	Provide area voltage support
2030	Ault Transformer Replacement Project	Replace the transformer at Ault due to condition/age.	Replace aging equipment and increasing area reliability

In-Service	Project Name	Description	Purpose
2027	Sand Creek Switchyard Project	Construct a new 115kV switchyard at Sand Creek tap.	Construct new switchyard to increase area 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.

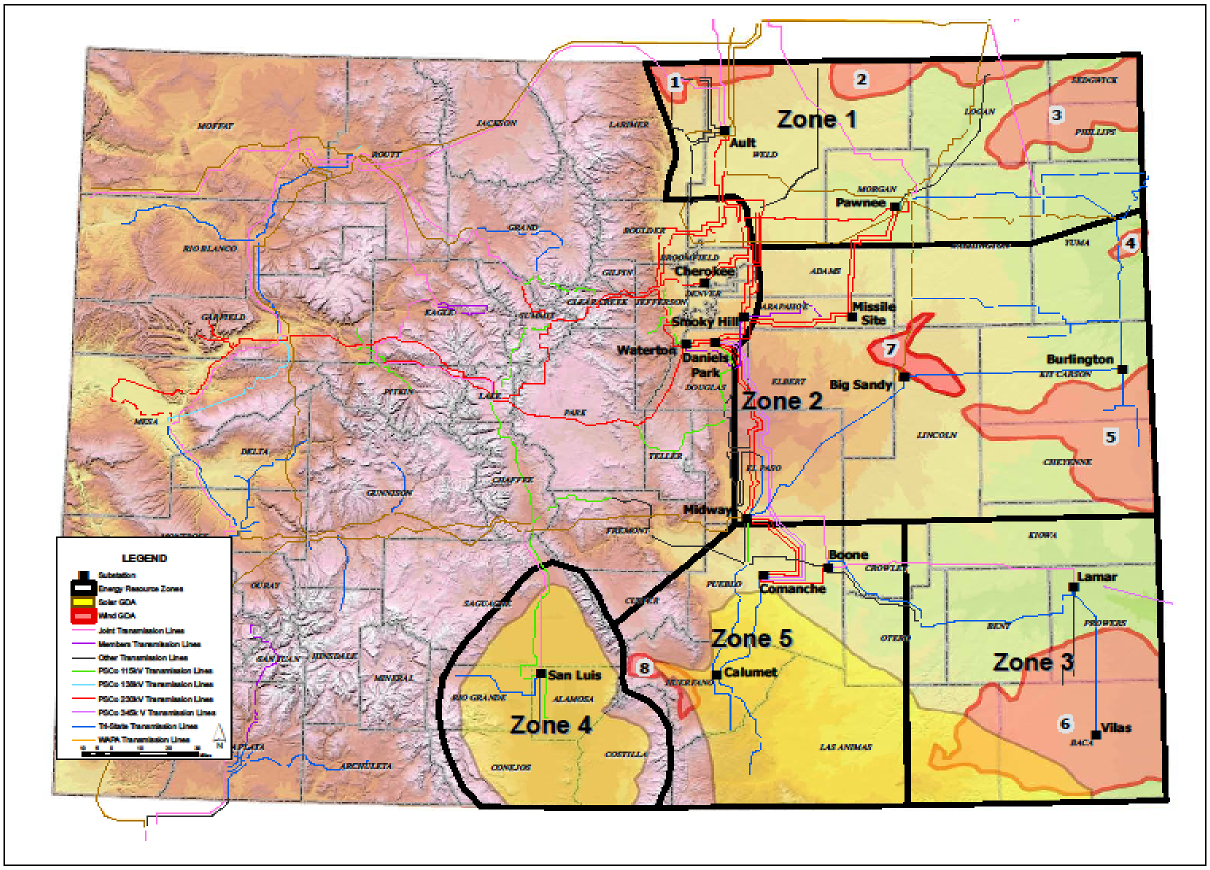
ERZ 4 (San Luis Valley)

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 7. 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

For the 2025 SB07-100 cycle, Black Hills referenced recent Large Generator Interconnection ("LGI") studies to evaluate the resource injection capacity from ERZ-5. All generators in the Black Hills generator interconnection queue are within ERZ-5. Recent LGI studies used a 2030 Heavy Summer ("HS") model 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. Black Hills also recently published an interactive heatmap that can be used to estimate incremental injection capacity for FERC Order No. 2023 compliance. This tool can be accessed with a link on OASIS. The map provides an approximation of the results of a network resource interconnection service request for a specific injection amount at tested points on the network. The heatmap results are informational only but can provide insight into transmission constraints related to energy resources in ERZ-5.

Black Hills SB07-100 Conclusions

The following transmission projects were identified as necessary to deliver electric power consistent with the development of energy resources located in ERZ-5.

The BHCT-G19, BHCT-G21, and BHCT-G38 LGI studies all identified a need to increase the rating of the Airport Industrial – Baculite Mesa 115 kV line. This rating increase can be accomplished with terminal upgrades and a reconductor using ACCC or other advanced conductor technology. The BHCT-G28 and BHCT-G38 LGI studies also identified a need to increase the rating of the Reader – Airport Memorial 115 kV line. This rating increase can be accomplished with terminal upgrades.

In 2025, Black Hills completed several 115 kV line rebuilds from West Station to West Canon that were identified as Network Upgrades for BHCT-G29. The 200 MW solar project went into suspension, but the rebuilds were completed to replace aging infrastructure. These recently completed projects improve the injection capability for projects in ERZ-5.

The BHCT-G35 and BHCT-G49 LGI studies identified a need for increased capacity between the Rattlesnake Butte and Reader 115 kV substations. LGI studies in this area have also shown thermal loading concerns on the Reader – Pueblo Plant – Hyde Park 115 kV lines. The BHCT Transitional Custer Study found the best solution is to cut an existing 115 kV line in the area to bring another source to the point of interconnection.

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 identified projects will be included in the Colorado Rule 3206 filing if the associated LGI projects execute an LGIA and provide notice to proceed.

B. Public Service Summary

Public Service began filing Senate Bill 07-100 (“SB 07-100”) reports in October 2007. Public Service developed comprehensive plans for eight transmission projects, targeting five Energy Resource Zones as outlined in C.R.S. 40-2-126(1). These initiatives are designed to enhance transmission capacity, facilitating the delivery of beneficial energy resources from the identified ERZs.

Of the eight projects, Public Service completed five projects, which are listed in Table 14 below. 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 (“Pathway Project”) in Proceeding No. 21A-0096E. Pursuant to SB 07-100, the Commission approved the Colorado Power Pathway Project (“Pathway Project”) in Decision No. C22-0270, Proceeding No. 21A-0096E. The Pathway Project is planned in three groups consisting of five segments:

Group 1: Segments 2 and 3 construction is complete and are in-service,

Group 2: Segment 1 construction has begun and is scheduled for in-service in 2026,

Group 3: Segment 4 construction has begun and is scheduled to be in service in 2027; Segment 5 is scheduled to be in-service in 2027.

Tables 14 and 15 below list the name of the project, the ERZ (“ERZ”) that the project would serve, a tentative schedule for implementation, and its current status.

Table 14. Public Service SB07-100 Completed Projects

No.	Project Name	ERZ	ISD	Status
1	Missile Site 230 kV Switching Station	2	2010	Project in-service as of November 2010.

No.	Project Name	ERZ	ISD	Status
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 in-service as of December 2012.
5	Pawnee-Daniels Park 345 kV	1,2	2019	CPCN granted on April 9, 2015. Project placed in service December 2019.

Table 15: Public Service SB07-100 Underway & Conceptual Projects

No.	Project	ERZ	ISD	Status
6	Colorado's Power Pathway (Segments 1- 5)	1,2,3,5	2025-2027	CPCN granted on June 2, 2022. Group 1-Segments 2 and 3 were energized in May 2025, Group 2-Segment 1 is scheduled to be in service in May 2026, Group 3-Segments 4 and 5 are scheduled to be in service in 2027.
7	Weld County Expansion	1	TBD	Studies ongoing through CCPG
8	San Luis Valley	4,5	TBD	Studies ongoing through CCPG
9	Lamar-Front Range 345 kV	2, 3	Cancelled	Replaced by Colorado's Power Pathway
10	Lamar-Vilas 230 kV	3	Cancelled	Replaced by Colorado's Power Pathway

A detailed description of the SB07-100 projects follows:

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.2. The project consists of building a 125-mile 345 kV transmission line from the Pawnee Substation in northeastern Colorado to the Daniels Park Substation, south of the Denver-Metro area. The project also will result in constructing a new Harvest Mile 345 kV Substation, near Smoky Hill Substation, and a new Harvest Mile-Daniels Park 345 kV line. The project also will interconnect with the Missile Site 345 kV Substation. This project was planned in accordance with Senate Bill 07-100, in that it will accommodate generation in designated Energy Resource ERZs 1 and 2. The project is in service as of Q4 2019, at a total cost of $174.6 million.

2. Projects Under Construction

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

The Pathway Project is described in Section III.C.X. The Commission issued a CPCN for the Pathway Project in Proceeding No. 21A-0096E. The Pathway Project consists of approximately 550 miles of a double circuit 345 kV transmission system that connects eastern Colorado to the Front Range, 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 Pathway Project is a $1.7 billion investment to improve the state's electric grid and enable future renewable energy development around the state.

The Commission did not approve construction of the May Valley – Longhorn Extension (Extension) in the January 2024 Phase II Decision regarding our Electric Resource Plan and Clean Energy Plan. We may bring a proposal to construct the May Valley – Longhorn

Extension and Longhorn Substation forward again in the future but have paused its further development as part of Colorado's Power Pathway. Development of Segments 1, 2, 3, 4, and 5 of Colorado's Power Pathway will continue.

Group 1: Segments 2 and 3 construction is completed including at Canal Crossing, Goose Creek and May Valley substation, which are now in-service.
Group 2: Segment 1 construction has begun in Morgan and Weld counties and is scheduled for in-service in 2026,
Group 3: Segment 4 construction has begun in Crowley, Kiowa and Pueblo counties and is scheduled to be in service in 2027; Segment 5 is scheduled to be in-service in 2027.

3. Conceptual Projects

Weld County Transmission Expansion (ERZ-1)

This plan is described in Section III.B.2 as a means to accommodate additional generation resources in ERZ-1. 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 Foothills Subcommittee is currently evaluating project alternatives to replace the 44 kV system in central and southern Weld County. 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 Foothills 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.C.3 and has been planned as a means to accommodate potential generation from ERZs 4 and 5, in addition to improving the reliability of the transmission system in the San Luis Valley area of Colorado. 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. The Reliability study is nearing completion. As part of the ongoing planning process, a detailed examination of both import and export capabilities is scheduled to take place in 2026.

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 Transmission Coordination and Planning Committee ("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 2025 as part of Black Hills' annual TCPC process. The primary kickoff took place on March 28, 2025, and the second, third and fourth invites occurred on June 27, 2025, September 19, 2025, and December 12, 2025. 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 2025 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 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 2025 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 2026 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 as individuals and organizations that have participated in previous Tri-State stakeholder meetings. When known, Tri-State also included stakeholders identified as being interested in specific proposed projects. The resulting non-governmental stakeholders included other utilities, Tri-State 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 2025, Tri-State hosted one transmission planning-related stakeholder outreach meeting in connection with development of the 2026 10-Year Transmission Plan. The meeting was held on December 10, 2025, 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 December 2025.

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 2026 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 2026 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 2024 Ten-Year Transmission Plan, Public Service hosted formal FERC Order 890/Rule 3627 stakeholder engagement meetings on March 27, 2024, December 19, 2024, March 13, 2025, and December 18, 2025.

For the meeting on December 18, 2025, 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 60 of the 275 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 https://www.oasis.oati.com/psco/index.html under "FERC 890/PUC 3627 Postings > Stakeholder Presentations".

2. Project-Specific Public Outreach

Colorado's Power Pathway

Public Service provides extensive reporting on public engagement associated with the Colorado's Power Pathway Project through semi-annual reporting filed in Proceeding No. 21A-0096E. Since the 2024 Rule 3627 Transmission Plan was filed, Public Service has hosted two additional public meetings associated with the Colorado's Power Pathway Project:

- June 12, 2024, Elbert County Landowners Meeting
- March 18, 2025, Arapahoe County Neighborhood Outreach Meeting

Barker Substation Project

Public Service has conducted a robust public outreach and engagement program to communicate with the community about the Barker Substation Project, which includes a new underground transmission line and new distribution substation located in the Lower Downtown neighborhood of Denver. The public outreach program was implemented in 2022 and will be continued for the duration of the Project. Public Service has established a website to provide public-facing information about the Barker Substation Project and its construction, available at https://xcelenergylacombetobarkersubstation.com/, and has also established a telephone information line and Project email inbox to enable the public to contact Public Service about the Project. Public Service has proactively contacted affected members of the public through a combination of direct outreach, flyers and postcards, news releases, digital advertising, and construction signage to reach affected members of the public. Prior to the start of construction, Public Service mailed 11,000 invitations directly to addresses within 1,000 feet of the Barker Substation and underground transmission line route for an open house. The open house was held on September 18, 2024 and hosted nine registered attendees.

Poder Substation

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 website, https://xcelenergypodersubstation.com/, as well as a project-specific email address and hotline phone number to provide information, take comments and respond to inquiries. Public Service hosted a public meeting on the Poder Substation Project on May 15, 2024.

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. The CCPG 3627 Subcommittee hosted a stakeholder meeting on December 9, 2025 to solicit stakeholder suggestions for the 2026 Rule 3627 filing. 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

Subcommittee Status

The CCPG Western Slope Subcommittee was established to evaluate near term (Years 1–5) and long term (Years 6–10) changes to the Western Slope transmission system that could affect system reliability, transfer capability, and WECC Path performance. The Subcommittee conducted high level, exploratory transmission planning studies intended to inform stakeholders and guide more targeted future analyses.

With the completion of the Western Slope 2023 Study Report (approved in 2025), the objectives of the subcommittee have been fulfilled and the Western Slope Subcommittee has been formally retired. The findings summarized below represent the subcommittee's final technical contributions and are intended to inform future CCPG planning efforts and follow-on studies conducted under other forums.

Summary Of Findings

1. Market Transfers Between CCPG and the Western Interconnection

   The study evaluated options to increase transfer capability across TOT 2A, including the addition of a ±1500 MW DC line between Craig and San Juan and a 500 kV AC connection between Craig and PacifiCorp's Gateway South.

   Key findings include:

   - The DC line provides controllable, bidirectional transfer capability and operational flexibility; however, Western Slope system strength—particularly TOT 5 and lower voltage facilities—becomes the limiting factor as DC transfers approach and exceed ~1000 MW.
   - Under high transfer conditions, TOT 5 is stressed beyond its current WECC Path rating, especially during Heavy Winter conditions when Western Slope generation is limited.
   - The 500 kV AC Craig–Gateway South connection does not independently increase transfer capability but significantly improves power flow distribution, reducing impacts on TOT 3 and providing a more direct path for northern generation.

   Overall, increased market transfer capability is feasible, but only when paired with additional reinforcement of the Western Slope transmission system.

2. Multipurpose Montrose – Tundra 345 kV Transmission Line

A conceptual 345 kV transmission line from Montrose to Tundra, routed similar to the existing Curecanti–Poncha–Midway corridor, was evaluated for its ability to strengthen TOT 5 and facilitate San Luis Valley exports.

Key findings include:

- The Montrose–Tundra 345 kV line resolves most benchmark overloads and materially improves system performance in both Heavy Summer and Heavy Winter conditions.
- The line is effective as a backbone reinforcement project, improving system resiliency and reducing reliance on underlying 115 kV and 230 kV networks.
- A connection between the Poncha 345 kV and 230 kV systems introduces new local overload risks, while removing the connection raises potential transient stability concerns due to long radial operation.
- San Luis Valley exports on the order of ~1,000 MW appear feasible but are contingent on how the Poncha area is integrated and on the performance of underlying transmission elements.

The study demonstrates that the 345 kV line is most effective as part of a coordinated, multivoltage transmission strategy rather than a standalone export solution.

3. Utilization of the Existing Western Slope Transmission System

The subcommittee evaluated whether targeted upgrades to the existing system could increase capacity across TOT 2A without constructing new major transmission lines.

Key findings include:

- Incremental upgrades to legacy 115 kV and 138 kV facilities provide the greatest near term benefit.
- Sequenced upgrades increased achievable TOT 2A transfers to approximately:
    - ~500 MW in Heavy Summer, and
    - ~500 MW in Heavy Winter, compared to significantly lower benchmark levels.
- Voltage level conversions (e.g., 230 kV to 345 kV) can initially reduce transfer capability unless transformer capacity upgrades are implemented concurrently.

These results highlight the importance of coordinated upgrades and confirm that the most limiting constraints are often low voltage lines and transformers, rather than primary 345 kV facilities.

Overall Conclusions

- Increased transfer capability and improved reliability on the Western Slope are achievable, but system reinforcement is required to avoid shifting constraints onto TOT 5 and underlying networks.
- Large new transmission projects and targeted upgrades serve complementary roles, with upgrades delivering near term benefits and new transmission addressing long term structural limitations.
- The studies provide actionable insight on constraints, thresholds, and tradeoffs, while identifying areas requiring more detailed analysis (e.g., transient stability, protection, and path rating processes).

With these findings documented, the CCPG Western Slope Subcommittee has concluded its work and has been retired, and future Western Slope planning efforts will proceed under broader planning activities.

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:

- September 8, 2020
- December 17, 2020
- January 13, 2022

- April 21, 2022
- July 28, 2022
- November 17, 2022
- May 1, 2024
- May 8, 2025
- June 10, 2025

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 multiple phases, with Phase I focused on alternatives which mitigate the existing reliability issues and increase load serving capabilities. A Phase 1.5 was initiated to look at the local reliability impacts of PSCO's ERP projects. Phase 2 will focus on alternatives that increase the transfer capability and provide 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
- November 29, 2023
- January 25, 2024
- August 27, 2024
- November 14, 2024
- January 23, 2025
- October 1, 2025
- December 17, 2025

Eight alternatives were studied in Phase I, each with the goal of increasing load serving capability of the transmission system feeding 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 1.5 will focus on identifying and mitigating local transmission issues related to PSCo's ERP, which included replacement of the Alamosa gas turbines and additional behind-the-meter small solar projects. As part of this analysis, PSCo has also proposed the following transmission upgrades:

- Remove terminal limits on Poncha-SLV 115kV
- Remove terminal limits on Ponca-SLV 230kV (evaluated in Phase 1)
- Remove terminal limits on SLV-Alamosa 115kV
- Uprate Alamosa-Mosca-SLV 69kV line to 800A
- New SLV-Alamosa 115kV line

Phase 2 focuses on alternatives that increase transfer capability and generation export from the valley to the Front Range. The ten proposed 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 5:
- Rebuild Poncha-Malta 115 kV line to 1200A
    - Alternative 5:
- Reconductor existing Poncha-Malta 115 kV line with carbon core
    - Alternative 6:
        - Poncha-Tundra 345 kV Double Circuit
            - Sensitivity with Carbon Core Conductor
    - Alternative 7:
        - Poncha-Midway + Poncha-Tundra 345 kV
            - Sensitivity with Carbon Core Conductor
    - Alternative 8:
        - New Poncha-Midway-Tundra DC Line
    - Alternative 9:
        - New Sub-Poncha-Midway 230 kV
            - Corresponds to Phase 1, alternative 8
            - Sensitivity with Carbon Core Conductor
    - Alternative 10:
        - Reconductor existing Poncha-Midway and SLV-Poncha with Carbon Core Conductor
    - Alternative 11:
        - 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

In addition to 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 machine's 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:

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

- 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 2026 Plan complies with all applicable NERC and WECC reliability standards and other applicable legal and regulatory requirements. These requirements include the RES and resource adequacy. Both requirements are addressed 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. As noted above, on September 4, 2024, the Commission issued Decision No. C24-0634, which changed the portfolio of resources to replace the 200 MW utility-owned solar with a 200 MW solar PPA, approved a 100 MW PPA solar project and a built transfer agreement (BTA) for a 50 MW battery storage project. On October 4, 2024, the Commission issued Decision No. C24-0715 to allow for the possibility of a BTA for the 200 MW solar project. On August 29, 2025, the Company filed a Motion requesting the Commission provide guidance on whether the Company should continue to seek and execute contracts with developers for the two remaining projects in the CEP, a 100 MW BTA solar project and a 200 MW PPA solar project, in the light of recently increased pricing. The Company filed updated modeling runs on October 3, 2025, then the Commission issued Decision No. C25-0805 stating that the Company should move forward with the 200 MW PPA solar project and not the 100 MW BTA solar project. Accordingly, the CEP was reduced from 350 MW (which includes a 50 MW battery storage project already fully approved by the Commission) to 250 MW. The Company is pursuing the completion of the 50 MW battery project and execution of the 200 MW solar PPA contract. 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 2026 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 2026 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 included 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 were also incorporated in Tri-State's 2023 Electric Resource Plan filing, which was subsequently approved by the Commission.

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

Pursuant to Rule 3627(b)(III), the Public Service Company of Colorado ("Public Service") files this annual Ten-Year Transmission Plan to demonstrate compliance with all state legal and regulatory requirements, including renewable energy standards and resource adequacy.

In accordance with the Colorado 2024 Renewable Energy Standard ("Colorado 2024 RES"), Public Service recently submitted its 2026-2027 Renewable Energy Compliance Plan (RE Compliance Plan) for Colorado Public Utilities Commission (the "Commission") approval in May 2025 in Proceeding No. 25A-0194E.

Pursuant to Rule 3627(b)(III) and consistent with Public Service's 2021 ERP and CEP, Public Service applied for Commission approval of its 2024 Just Transition Solicitation ("JTS") in October 2024 in Proceeding No. 24A-0442E. In November 2025, the Commission issued their written approval of the Phase 1 assumptions and process. Information on Public Service's JTS and programming is available at:

https://www.xcelenergy.com/company/rates_and_regulations/resource_plans/just_transition.

Additional information on Public Service's JTS resource plan filings can be accessed through the Commission's e-filing system by searching for Proceeding No. 24A-0442E at: https://www.dora.state.co.us/pls/efi/EFI_Search_UI.search.

Information on Public Service's Resource Plans and Resource Adequacy requirements is available at:

https://www.xcelenergy.com/company/rates_and_regulations/resource_plans.

Information on Public Service's RE Plans and Reports is available at:

https://www.xcelenergy.com/company/rates_and_regulations/filings/renewable_energy_plans_and_reports.

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

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

1. Black Hills Participation Strategy

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

2. Tri-State Participation Strategy

Attachment K to Tri-State's OATT demonstrates Tri-State's transmission planning processes consistency with FERC Order No. 890 planning principles. As discussed previously in this 2026 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://xcelnew.my.salesforce.com/sfc/p/1U0000011ttV/a/8b000002YFCh/YQivX0M31Um75bEdwrD0SMWAVk0g5iHvTO6tv3N0fjM.[15] 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.

[15] The Xcel Energy OATT must be downloaded from this link to view the entire contents of the document.

6) Participate in a regional transmission planning process that has an interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions.

WestConnect is one of three planning "regions"[16] within WECC established for regional transmission planning to comply with Order 1000. Public Service, Tri-State, and Black Hills have designated WestConnect as their Order 1000 compliant planning regions. The WestConnect planning process is described in Black Hills', Tri-State's, and Public Service's OATTs (Attachment K, K, and R, respectively; links are provided above) as well in documentation found on the WestConnect website: http://www.westconnect.com/. The WestConnect website also houses information and announcements for many public planning meetings. WestConnect accepts stakeholder input throughout the planning process.

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

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.

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

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. Black Hills Powerline Trail Compliance

Black Hills Energy will notify local governments of the potential for construction of a powerline trail when: (1) siting a new transmission line, (2) expanding an existing transmission line, (3) applying to local counties for 1041 permits. These notifications will occur if the transmission line will be extended by more than one mile or the line capacity will be increased by more than 10%. More information on Black Hills' compliance with the Powerline Trails Act can be found at House Bill 22-1104 "The Powerline Trails Act" | Black Hills Energy

2. Tri-State Powerline Trail Compliance

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

Table 11.

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.

3. 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://corporate.my.xcelenergy.com/s/transmission/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, such as projects that rebuild existing transmission lines that have reached the end of their useful life to modern design standards, 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 12.

Transmission Line Project	Project Location (County)
Colorado's Power Pathway	Weld, Morgan, Washington, Kit Carson, Cheyenne, Kiowa, Crowley, Pueblo, El Paso, Lincoln, Elbert, Arapahoe
Circuits 5111 and 5707: Daniels Park – Prairie – Greenwood Uprate	Douglas, Arapahoe
Circuit 5709: Greenwood – Arapahoe Uprate	Arapahoe, Denver
Circuit 9335: Arapahoe – South Tap – Bancroft Uprate	Denver, Jefferson
Circuit 5107: Daniels Park – Santa Fe Uprate	Douglas
Circuits 5167 and 5285: Smoky Hill - Buckley - Tollgate - Jewell – Leetsdale Uprate	Arapahoe, Denver
Circuit 5625: Denver Terminal – Elati Uprate (Underground)	Denver
Circuit 9955: Leetsdale – Harrison Uprate (Underground)	Denver
New 115 kV Transmission Line: Cherokee - New Substation A	Adams, Denver
Circuit 9542: Cherokee - New Substation A	Adams, Denver
Circuit 9546: Cherokee -Mapleton - New Substation A Uprate	Adams, Denver
Circuit 9549: Cherokee -Conoco - New Substation A Uprate	Adams, Denver
Circuits 9055, 9558, and 9464: Cherokee - Federal Heights - Semper – Broomfield Uprate	Adams, Jefferson, Broomfield
Circuit 5283: Leetsdale – Elati 230 kV Underground Transmission Line Upgrade	Denver
Avon – Gilman 115 kV Transmission	Eagle

Kestrel Substation and Transmission Line	Adams
Circuit 6670: De Beque - Ute Rifle Rebuild	Mesa, Garfield
Circuit 6689: Uintah – Fruita Rebuild	Mesa
Circuit 6584: Mitchell Creek - Ute Rifle Rebuild	Garfield
Circuit 6671: Vineland - Ute Junction Rebuild	Mesa
Circuit 6913: Alamosa Terminal - Homelake - Rio Grande Rebuild	Alamosa
Circuit 6927: Mirage Junction to Saguache Rebuild	Saguache
Circuit 6914: Alamosa Terminal – Romeo – Antonito Rebuild	Alamosa, Conejos
Circuits 9254 and 9257: Leadville – Climax/Robinson Rack Rebuild	Lake, Eagle, Summit
Circuit 9255: Malta - Otero Tap Rebuild	Lake, Chaffee
Circuit 9256: Hopkins - Basalt Rebuild	Garfield, Eagle
Circuit 9216: Boulder Hydro - Boulder Rebuild	Boulder
Circuits 9054, 9046, and 9688: Valmont – Ridge/El Dorado Rebuild	Jefferson, Boulder

Public Service provides notice to all relevant 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. This notice has been provided to local permitting authorities for each transmission line project for which a local permit is required and for which Public Service has commenced the permit application process. For projects for which Public Service has not yet commenced the local permitting process, Public Service will provide notice to local jurisdictions for all projects that fall under the requirements of the Powerline Trails Act.

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.[17] 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

[17] *See, e.g.,* Proceeding No. 20M-0008E, Decision No. C20-0213-I, (mailed date April 7, 2020), page 8, ¶ 23 ("The Joint 10-Year Transmission Plan and 20-Year Conceptual Scenario Report as supplemented with information required by this Decision shall include all models used and an explanation and copy of model outputs. Additionally, updates shall include discussion of the Basis of Plan, Identified Issues, and any Resource Requirements including Costs, Quality Metrics, and Stakeholder Register.")

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 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.

Consistent with Attachment R to the Tri-State OATT, Tri-State has developed a ratings methodology in alignment with FERC Order No 881. Tri-State has received deferral of the implementation date for this methodology up to and including October 15, 2027. 191 FERC ¶ 61,161 (2025) (Docket No. ER22-2360-000).

b. Public Service Ratings

Documentation of Public Service FAC-008-005 methodology can be found in Appendix P. Public Service will implement the "Ambient Adjusted Rating" line rating methodology requirements of FERC Order No. 881 consistent with Attachment S to the Xcel Energy Operating Companies Joint OATT. Public Service has received deferral of the implementation date for this methodology until September 1, 2026. 191 FERC ¶ 61,094 (2025) (Docket No. ER22-2356).

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 2022, 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' 2022 ERP in Colorado 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 2024 load forecast data.

Table 13. Tri-State Summer 2024 Demand Forecast (MW)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Summer Peak Demand (MW)	3,463	3,516	3,591	3,697	3,782	3,854	3,906	3,989	4,048	4,098	4,226

c. Public Service Forecasts

The load forecast referenced by this filing is Public Service's Fall 2024 load forecast, as filed with the Commission on October 15, 2024 in the Just Transition Solicitation in Proeeding No. 24A-0442E and on March 31, 2025 in the ERP Annual Progress Report in Proceeding No. 21A-0141E. Table 18 below shows the Public Service load forecast. Public Service notes that adjustments to this load forecast are expected through the Phase I process in the Just Transition Solicitation proceeding.

Table 14. Public Service Company Fall 2024 Demand Forecast (MW)

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	
25	Res Base Forecast	3,334	3,344	3,344	3,350	3,372	3,391	3,409	3,331	3,362	3,383	+
26	Non-Res Base Forecast	3,344	3,398	3,556	3,891	4,359	4,780	5,209	5,417	5,549	5,629	+
27	DSM Forecast	(33)	(50)	(82)	(117)	(148)	(179)	(216)	(266)	(302)	(351)	-
28	BE Forecast	3.8	8.8	34.4	62.5	93.5	126.2	155.0	185.0	211.3	235.3	+
29	EV's Forecast	47	85	134	198	275	357	440	631	728	826	+
30	IVVO Forecast	4	3	3	3	3	2	2	2	1	1	-
31	Oil&Gas Forecast	81	99	144	189	264	364	364	364	364	364	+
32	Solar Forecast	288	326	361	397	419	464	514	272	290	299	-
33	**Retail Forecast**	**6,551**	**6,656**	**6,929**	**7,406**	**8,090**	**8,730**	**9,278**	**9,920**	**10,224**	**10,489**	*33 = 25 + 26 - 27 + 28 + 29 - 30 + 31 - 32*
34	Wholesale Forecast	588	157	159	31	31	34	36	36	37	37	+
35	**Obligation Forecast**	**7,138**	**6,813**	**7,088**	**7,438**	**8,121**	**8,764**	**9,314**	**9,955**	**10,261**	**10,526**	*35 = 33 + 34*
36	Solar Forecast	288	326	361	397	419	464	514	272	290	299	+
37	**PSCo Native Load Forecast - Spring 2024 (Base) (MW**	**7,426**	**7,139**	**7,450**	**7,835**	**8,540**	**9,228**	**9,828**	**10,227**	**10,552**	**10,825**	*37 = 35 + 36*

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.

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.

Public Service notes that the load forecast referenced by this 10-Year Plan is not necessarily the load forecast used in the planning of any of the transmission projects identified in this 10-Year Plan. Load assumptions used within the planning of any specific transmission project are typically provided in a completed transmission planning study report. Consistent with the Commission's directives in Decision No. C22-0319-I, Public Service provides the following supporting information related to its 2036 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 15.

2036 Summer Peak – Native Load (MW)	2036 Winter Peak – Native Load (MW)	2036 Reduced summer peak load when BTM generation is maximized (MW)	2036 Reduced winter peak load when BTM generation is maximized (MW)
11,173	10,871	8,251	7,093

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 2022 Black Hills ERP (Proceeding No. 22a-0230E); specifically, Attachment LS-1, which is included in Appendix N of this document.

b. Tri-State DSM

Load forecasts provided for bulk electric transmission planning typically include existing DSM and other load-reducing programs, including Utility Members' energy efficiency programs and local distributed generation. These programs are reflected in the power flow model as reduced load and are inherently included in studies. For transmission planning, load forecasts that contain load-reducing factors may be used for specific projects or for individual Tri-State Utility Members with DSM, local distributed generation, or other energy efficiency programs. For such cases, please refer to individual project planning studies. For Tri-State's system load forecast, these are described in Tri-State's 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 is referenced in Section VIII.C.1.c. above. Public Service's 2024-2026 Demand Side Management and Beneficial Electrification Plan was approved by the Commission in November 2024 in Proceeding No. 23A-0589EG. In April 2025, Public Service filed its 2024 Demand-Side Management Annual Status Report in Proceeding No. 22A-0315EG.

D. Generation and Dispatch Assumptions

Generator and associated equipment models are typically included in the WECC Annual Base Case[18] Compilation Schedule base cases as required by the Data Preparation

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

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

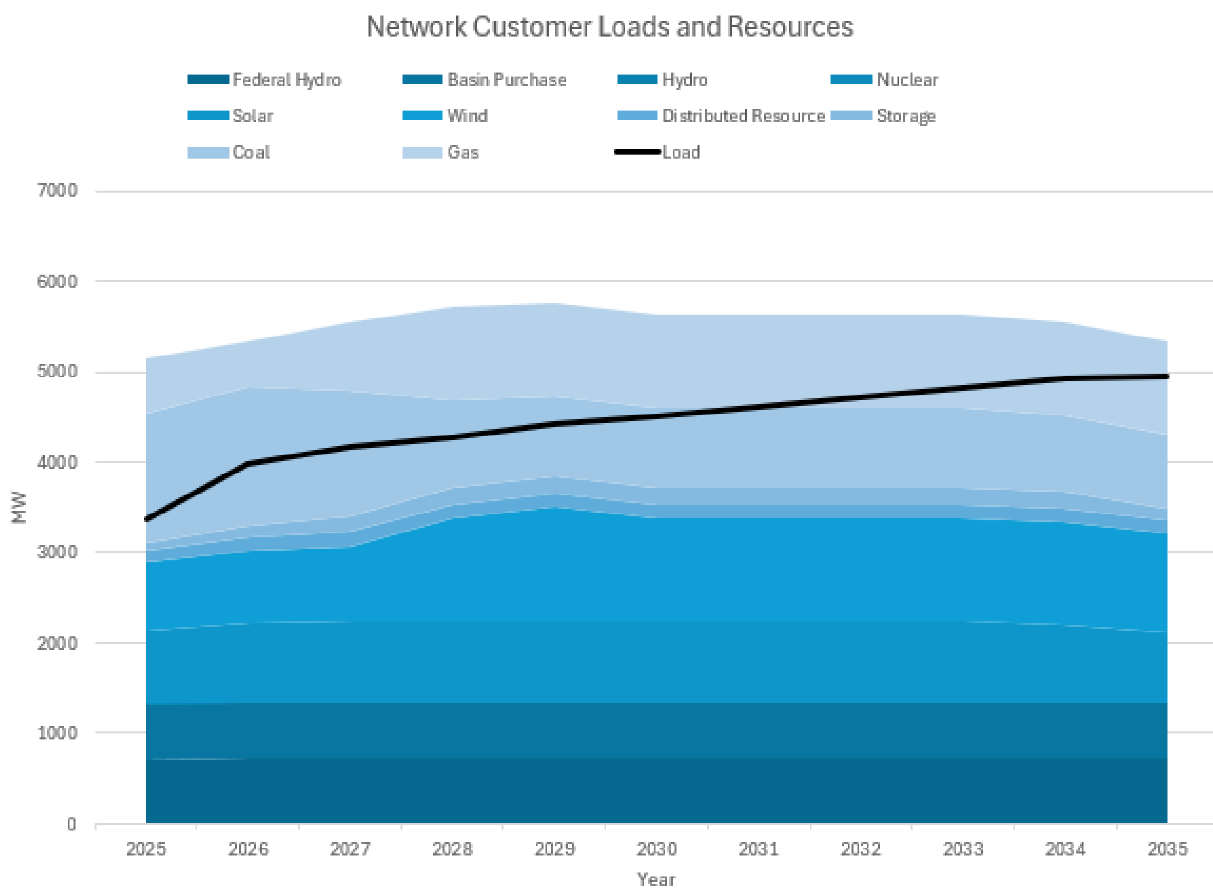
1. Black Hills Assumptions

At the most basic level, Black Hills dispatches existing generation to meet the demand requirements of its system, including load and losses. The objective of a particular study often drives the individual generator dispatch levels. For example, a peak demand summer baseline scenario may consist of a majority of dispatchable baseload generation online and an appropriate mix of wind and solar PV to meet the demand requirements. An off-peak demand spring or fall scenario may have the available wind generation dispatched at its nameplate capacity with the dispatchable baseload generation and solar generation reduced to capture the impacts of that particular dispatch pattern. Existing power purchase agreements and other contractual arrangements may be reflected in certain study scenarios to further stress the transmission system. Black Hills also may include speculative generation (as identified in the current version of the Black Hills Colorado Electric Generation Interconnection Request Queue, included in Appendix 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"), United Power ("UP"), Mountain Parks Electric, Inc ("MPEI"), 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. The diagram below reflects feedback received from the 2025 request.



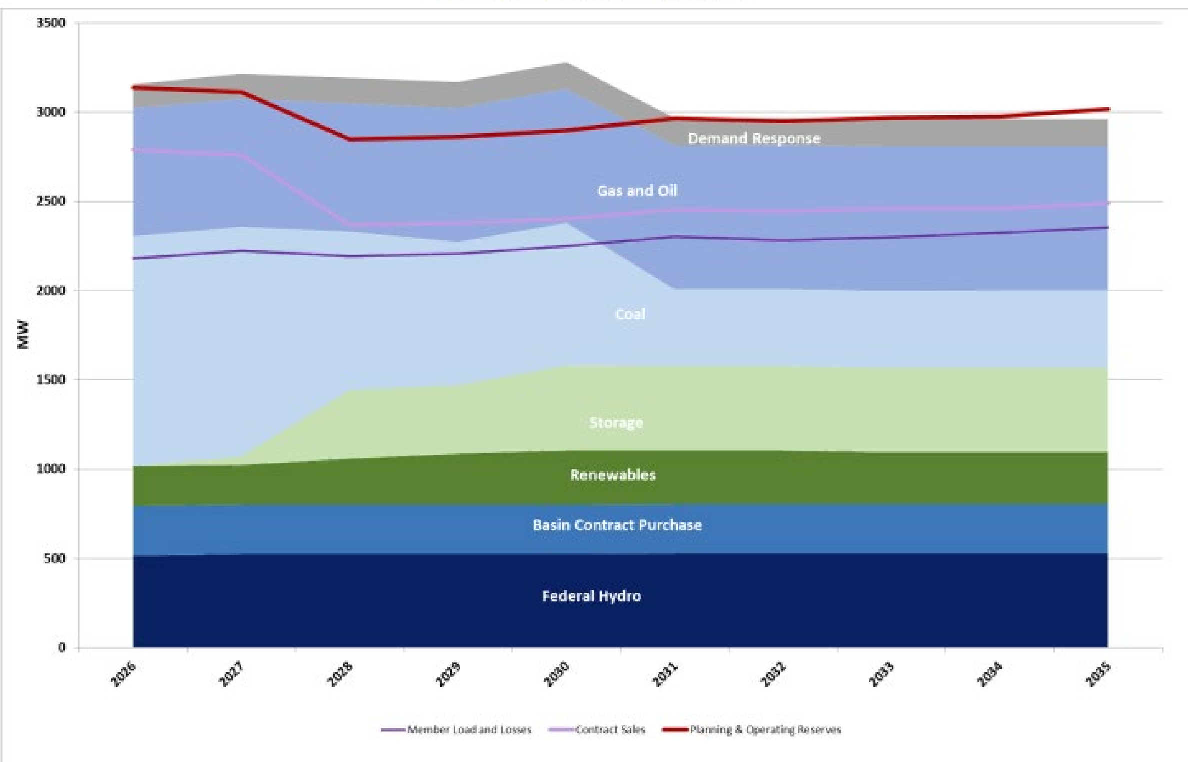
Generation assumptions, including dispatch assumptions, and corresponding data for other transmission plans are project-specific. Therefore, the individual transmission studies should be referenced for generation assumptions relative to each such project.

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 2026 through 2035 in Appendix O. Tri-State is also providing the Load and Resources table associated with Tri-State's 2025 Annual Progress Report associated with its 2023 Electric Resource Plan[19,20]

TABLE 1 – 10-YEAR DEMAND AND ENERGY FORECAST

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Annual Energy Sales (GWh)	13,051	13,110	13,455	13,642	13,830	14,049	14,289	14,521	14,773	15,036
Winter Peak Demand (MW)	1,865	1,739	1,778	1,825	1,847	1,888	1,886	1,955	1,998	2,038
Summer Peak Demand (MW)	2,344	2,423	2,454	2,431	2,472	2,535	2,583	2,635	2,646	2,629

FIGURE 3 –LOAD AND RESOURCES



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[19] This table, as well as supporting information, can be found in Proceeding No. 23A-0585E.

[20] Supplemental information can also be found at https://www.tristategt.org/resource-planning

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 incorporates by reference the Evaluation of Existing Resources provided in Phase I of the

Just Transition Solicitation resource plan in Proceeding No 24A-0442E.[21] Consistent with the Commission's directives in Decision No. C22-0319-I, Public Service provides the following supporting information concerning its 2036 generation forecasts, and further incorporates by reference the generation data provided in Phase I of the Just Transition Solicitation resource plan in Proceeding No 24A-0442E.[22] 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 Phase I of the Just Transition Solicitation in . Public Service expects that the values identified in this table will change based on the outcome of the Near-Term Procurement in Proceeding No. 21A-0141E and the selection of a Phase II resource portfolio in the Just Transition Solicitation, and may also be modified by the Commission's Phase I decision in the Just Transition Solicitation, but references data initially filed in Public Service's Phase I direct case in this Ten-Year Plan based on the timing the timing of the Phase I decision.

Table 16. 2036 Public Service Forecasted Electric Resource Planning System Data

Expected summer peak coincident generation mix	Expected winter peak coincident generation mix
20% natural gas 41% wind 20% utility-scale, CSG and BTM solar 14% storage	25% natural gas 49% wind 25% storage

[21] *See* Proceeding No. 24A-0442E, Hearing Exhibit 101, Attachment JWI-2, Volume 2, at Section 2.4 (pages 80-98).

[22] *See, e.g.,* Proceeding No. 24A-0442E, Hearing Exhibit 101, Attachment JWI-2, Volume 2, at Section 2.10 (pages 146-170).

E. Methodologies

1. System Operating Limits (FAC-011)

As stated in the NERC Glossary of Terms Used in Reliability Standards, a System Operating Limits ("SOL") is defined as the value (such as MW, MVAr, Amperes, Frequency, or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-Contingency equipment of Facility ratings)
- Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

The purpose of approved FAC-011-4, which is applicable to Reliability Coordinators, is to ensure that SOLs used in the reliable operation of the BES are determined based on an established methodology or methodologies. Approved FAC-014-3 requires that Transmission Operators establish SOLs for their portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. The established SOL is not required to be publicly available.

a. Black Hills SOL

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

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

b. Tri-State SOL

Tri-State as a Transmission Operator in accordance of FAC-014-3, establishes SOLs for its portion of the BES per the applicable Reliability Coordinator's SOL methodology. Tri-State's determines the appropriate SOLs are summarized below:

- BES Transmission Line and transformer SOLs are exceeded when loading exceeds 100% of an established emergency limit for a pre-determined amount of time.
- BES Voltage SOLs are exceeded when the emergency voltage limit is exceeded.

Tri-State's Engineering Standards Bulletin outlines the rating methodology for determination of emergency facility ratings. However, minor exceptions can exist where a determined SOL is different than the Facility Rating as the SOL limitation is governed by voltage stability or transient stability at a value lower than the equipment capabilities.Public Service SOL

As a Transmission Operator, Public Service follows the SOL Methodology adopted by the Southwest Power Pool in its role as Reliability Coordinator. Southwest Power Pool's SOL Methodology for the Western Interconnection is available at:

https://spp.org/documents/71218/spp%20west%20sol%20methodology%208300ext00132%20v2.0.pdf.

2. Available Transmission System Capability Methodology (NAESB WEQ-023)

Available Transmission System Capability Methodology is available and posted per NAESB WEQ-023e.

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 NAESB Business Practice Standard WEQ-023. 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 NAESB Business practice Standard WEQ-023 simulation studies result insufficient 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 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 (NAESB WEQ-023)

Capacity Benefit Margin ("CBM") methodology is available and posted per NAESB WEQ-023.

a. Black Hills Capacity Benefit Margin

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 (NAESB WEQ-023)

NAESB WEQ-023 requires that each Transmission Operator prepare and keep current a Transmission Reliability Margin Implementation Document ("TRMID").

a. Black Hills Transmission Reliability Margin

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 inter-connection, 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 may be posted at the following links:

https://www.rmao.com/public/wtpp/PSCO_Studies.html
https://www.oasis.oati.com/psco/index.html
https://corporate.my.xcelenergy.com/s/transmission/planning

H. In-Service Dates

Information concerning the expected in-service date for each utility's facilities identified in the 2026 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 2024 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. 2026 CPUC Rule 3627 Appendices

Appendix A:	Colorado Transmission Map
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