





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, 2016

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ACRONYMS AND ABBREVIATIONS

Acronym or Abbreviation	Term
2016 Plan	2016 Ten-Year Transmission Plan for the State of Colorado
ALJ	Administrative Law Judge
ARPA	Arkansas River Power Authority
ATC	Available Transfer Capability
ATCID	Available Transfer Capability Implementation Document
BES	Bulk Electric System
Black Hills	Black Hills Colorado Electric Utility Company, L.P. d/b/a Black Hills Energy
СВМ	Capacity Benefit Margin
CBMID	Capacity Benefit Margin Implementation Document
CCPG	Colorado Coordinated Planning Group
CEII	Critical Energy Infrastructure Information
Commission or CPUC	Colorado Public Utilities Commission
Companies	Black Hills, Tri-State and Public Service
Company	Black Hills, Tri-State or Public Service
CPCN	Certificate of Public Convenience and Necessity
СРР	Clean Power Plan
CPWG	Conceptual Planning Work Group
CSU	Colorado Springs Utilities
DSM	Demand Side Management
EPA	Environmental Protection Agency
EPAct	Energy Policy Act of 2005
ERP	Electric Resource Plan
ERP/APR	Electric Resource Plan Annual Progress Report
ERZ	Energy Resource Zone
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
НОА	Homeowners Association

Acronym or Abbreviation	Term
HVDC	High Voltage Direct Current
IEA	Interwest Energy Alliance
IREA	Intermountain Rural Electric Association
kV	Kilovolt
L&R	Load and Resource
LGIP	Large Generator Interconnection Procedures
LRCC	Loveland Reliability Control Center
LTP	Local Transmission Plan
MEAN	Municipal Electric Agency of Nebraska
MW	Megawatts
MVAR	Mega Volt Ampere Reactive
MVEA	Mountain View Electric Association
NECO	Northeast Colorado
NERC	North American Electric Reliability Corporation
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OCC	Office of Consumer Counsel
0.1	FERC Order No. 1000 Transmission Planning and Cost Allocation by
Order 1000	Transmission Owning and Operating Public Utilities
PA	Planning Authority
PCC	Planning Coordination Committee
PNM	Public Service Company of New Mexico
PRPA	Platte River Power Authority
Public Service	Public Service Company of Colorado
RES	Renewable Energy Standard
RTO	Regional Transmission Organization
SB07-100	Colorado Senate Bill 07-100
Sierra	Sierra Area Planning Group

Acronym or Abbreviation	Term
SLV	San Luis Valley
SOL	System Operating Limits
SPG	Sub-regional planning group
SWAT	Southwest Area Transmission Group
SWEP	Southwest Weld Expansion Project
ТСРС	Transmission Planning and Coordination Committee
TEPPC	Transmission Expansion Planning Policy Committee
ТР	Transmission Provider
Tri-State	Tri-State Generation and Transmission Association, Inc.
TRMID	Transmission Reliability Margin Implementation Document
ттс	Total Transfer Capability
WECC	Western Electricity Coordinating Council
Western/WAPA	Western Area Power Administration (also WAPA)

I. Executive Summary

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

In 2011, the Colorado Public Utilities Commission ("Commission" or "CPUC") adopted Rules 3625 through 3627, which set forth requirements for transmission planning applicable to Commission-regulated utilities. The rules require these utilities to establish a process to coordinate the planning of additional electric transmission in Colorado in a comprehensive and transparent manner. The process is to be conducted on a statewide basis and is to take into account the needs of all stakeholders. This 2016 Ten-Year Transmission Plan for the State of Colorado ("2016 Plan") is the result of a cooperative effort among Black Hills Colorado Electric Utility Company, L.P. d/b/a Black Hills Energy ("Black Hills"), Tri-State Generation & Transmission Association, Inc. ("Tri-State"), and Public Service Company of Colorado ("Public Service") (each a "Company" and collectively the "Companies"), and is the third ten-year transmission plan that the Companies have filed under Rule 3627.

Since filing the first ten-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 2016 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 ten years in the state of Colorado. The 2016 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 2016 Plan and the individual transmission projects included in the 2016 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 2016 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 addressed the interests of stakeholders.

When possible, individual transmission projects have been designed to accommodate the collective needs of multiple TPs and stakeholders. Changes in regulatory requirements, regulatory approvals, or underlying assumptions such as load forecasts, generation, or transmission expansions, economic issues, and other utilities' plans may impact this 2016 Plan and could result in changes to in-service dates or project scopes. Public policy initiatives, such as future federal and local mandates may also impact the 2016 Plan and the transmission planning process in general. Public policy impacting the Companies include Senate Bill 07-100, and most recently the U.S. Environmental Protection Agency's ("EPA") Clean Power Plan ("CPP") and the corresponding Colorado state compliance plan. The final rules related to CPP were published in the Federal Register on October 23, 2015, and the state of Colorado is in the early stages of formulating its plan for complying with CPP. The Companies are engaged with each other and relevant state agencies in the development of Colorado's CPP compliance plan which is due in September, 2016. While the Companies anticipate that aspects of the Colorado CPP compliance plan may impact transmission plans in the ten-year planning timeframe, those impacts are not yet known and it is premature to include in the 2016 Plan specific transmission projects related to CPP. The Companies will continue to coordinate with each other and stakeholders with

respect to the transmission planning implications of CPP and expect to address this issue in the next Ten-Year Transmission Plan.

Section II provides background information about the transmission planning processincluding coordinated regional and statewide efforts, as well as internal practices of each Company—while Sections IV, V and VI 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 2016 Plan identifies 47 significant transmission projects. These projects are listed in Table 1 and shown geographically in Figure 1. Figures 2 and 3 depict area maps for Denver-Metro and Black Hills Ten-Year Transmission Plan, respectively. Larger maps of the state plan showing chronological stages of development are provided in Appendix A. Larger versions of the Denver-Metro and Black Hills maps are provided in Appendices B and C.

Section III of this report provides 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-G.

Map #	Project Name	In-Svc ⁽¹⁾	Cost (MIL)	BH	тs	PS	Purpose
1	Rosedale Substation	2015	\$10			\checkmark	R
2	W. Station – Desert Cove 115 kilovolt ("kV")	2015	\$1.3	\checkmark			R
3	Ptarmigan Substation	2014	\$22.0			\checkmark	L
4	Monfort – DCP Midstream 115 kV Transmission	2015	\$3.5			\checkmark	L
5	Baculite Mesa – Fountain Lake 115 kV Upgrade (and Fountain Lake Substation)	2016	\$2.0	\checkmark			G,R
6	Burlington – Wray 230 kV	2016	\$66.5		\checkmark		L
7	Happy Canyon Substation	2016	\$3.0			\checkmark	L

Table 1. Significant transmission projects included in the 2016 Plan

Map #	Project Name	In-Svc ⁽¹⁾	Cost (MIL)	вн	тs	PS	Purpose
8	Keller – Front Range 230 kV	2017					
9	Rifle – Parachute 230 kV #2	2016	\$28.0			\checkmark	L,R
10	Pueblo West Tap Line Uprate	2016	\$0.6		\checkmark		R
11	Boone – Nyberg 115 kV	2016	\$10.0	\checkmark			R
12	Boone 115/69 kV Transformer	2016	\$3.0	\checkmark			R
13	Rattlesnake Butte 115 kV Terminal Addition	2016	\$1.9	\checkmark			G
47	Cherokee Ridge 230 kV Conversion	2016	\$5.5			\checkmark	R
14	Avery Distribution Substation	2017	\$16.0			\checkmark	L
15	La Junta 115/69 kV Transformer #2	2017	\$3.0	\checkmark			R
16	Portland 115/26 kV Transformer Replacement	2017	\$2.5	\checkmark			R
17	Lost Canyon Main Switch 115 kV	2018	\$17.8		\checkmark		R
18	San Juan Basin Energy Connect	2018	\$113.0		\checkmark		R
19	Southwest Weld Expansion Project	2018	\$112.0		\checkmark	\checkmark	R
20	Western Colorado Trans Upgrade	2018	\$122.0		\checkmark		R
21	Arequa Gulch 115 kV Capacitor	2018	\$0.9	\checkmark			R
22	Avon – Gilman 115 kV	2019	\$20			\checkmark	R
23	Moon Gulch Distribution Substation	2019	\$2.0			\checkmark	L
24	Thornton Distribution Substation	2019	\$30.0			\checkmark	L
25	Falcon – Midway 115 kV Upgrade	2019	\$5.4		\checkmark		R
26	W. Station – Canon West 115kV	2019	\$23.5	\checkmark			L,R
27	North Canon 115/69 kV Substation	2019	\$9.9	\checkmark			L,R
28	Ault – Monfort 115 kV Transmission	2019	\$8.0			\checkmark	L,R
29	Burlington - Lamar 230 kV	2020	\$53.0		\checkmark		R
30	Big Sandy – Calhan 230 kV	2021	\$53.0		\checkmark		L
31	Rosedale – Milton 230 kV	2022	TBD		\checkmark	\checkmark	L,R
32	Weld – Rosedale 230 kV	2022	TBD		\checkmark	\checkmark	L,R
33	Pawnee – Daniels Park 345 kV	2022	\$180.0			\checkmark	G,R
34	San Luis Valley – Poncha 230 kV	2022	\$58.0		\checkmark	\checkmark	R
35	Bluestone Valley Substation	TBD	TBD			\checkmark	L

Map #	Project Name	In-Svc ⁽¹⁾	Cost (MIL)	вн	тs	PS	Purpose
36	Glenwood – Rifle 115 kV	TBD	TBD			\checkmark	L,R
37	Lamar – Front Range 345 kV	TBD	\$900.0		\checkmark	\checkmark	G,R
38	Lamar – Vilas 230 kV	TBD	\$90.0		\checkmark	\checkmark	G
39	Parachute – Cameo 230 kV #2	TBD	\$52.0			\checkmark	L,R
40	Weld County Expansion	TBD	TBD			\checkmark	G,R
41	Rifle (Ute) – Story Gulch 230 kV	TBD	TBD			\checkmark	L
42	Wheeler – Wolf Ranch 230 kV	TBD	TBD			\checkmark	L
43	Hayden – Foidel – Gore Loop	TBD	TBD			\checkmark	R
44	Boone – Walsenburg 230 kV	TBD	\$45.0		\checkmark		L,R
45	Boone – Lamar 230 kV Line	TBD	\$65.0		\checkmark		R
46	Wilson Substation	TBD	\$4.0			\checkmark	L

Key: R – Reliability, L – Load-serving, G – Generation/SB100,

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

Figure 1. Statewide map of significant transmission projects in the 2016 Plan



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2014 - 2015	2016	2017	2018	2019
1 Rosedale Substation (New, PSCo)	Baculite Mesa-Fountain Lake115 kV	Avery Distribution Substation (New, PSCo)	Lost Canyon Main Switch 115 kV (New, Tri-	Avon – Gilman 115 kV (New, PSCo)
W.Station-Desert Cove 115 kV (Upgrade, BHCE)	Burlington-Wray 230 kV (New, Tri-State)	La Junta 115/69 kV Transformer #2 (New, BHCE)	San Juan Basin Energy Connect Project (Tri-	Moon Gulch Distribution Substation (New, PSCo)
3 Ptarmigan Substation (New, PSCo)	Happy Canyon Substation (New, PSCo)	Portland 115/89 kV Transformer Replacement	State)	Thornton Distribution Substation (New, PSCo)
Monfort-DCP Midstream 115kV Transmission	Nixon – Front Range 230 kV (CSU)	(Upgrade, BHCE)	State, PSCo)	Falcon-Midway 115 kV Upgrade (Tri-State)
(124,1000)	Rifle-Parachute 230 kV #2 (New, PSCo)		Western Colorado Transmission Upgrade Project (Upgrade, Tri-State)	W. Station – Canon West 115kV Project (New, BHCE)
	Pueblo West Tap Line Uprate (Upgrade, Tri- State)		Arequa Gulch 115kV Capacitor (New, BHCE)	North Canon 115/69 kV Substation (New,
	Boone-Nyberg 115 kV (New, BHCE)			Ault – Monfort 115kV Transmission (New,
	Boone 115/69 kV Transformer (Replacement, BHCE)			PSCo)
	Rattlesnake Butte 115 kV Terminal Addition (Upgrade, BHCE)			
	Cherokee – Ridge 230kV Conversion (New, PSCo)			
2020	2021	2022	2023	Beyond 2023 or ISD TBD
Burlington – Lamar 230 kV (345 kV) (Tri-State)	Big Sandy-Calhan 230 kV (Tri-State)	Rosedale – Milton 230 kV (New, PSCo, Tri-		(se) Bluestone Valley Substation (New, PSCo)
ľ		State)		30 Glenwood-Rifle 115 kV (Upgrade, PSCo)
		State)		Damar-Front Range 345 kV (Tri-State, PSCo)
		Pawnee-Daniels Park 345 kV (New, PSCo)		Lamar-Vilas 230 kV (Tri-State, PSCo)
		San Luis Valley - Poncha 230 kV (Tri-State, PSCO)		Parachute-Cameo 230 kV #2 (New, PSCo)
				Weld County Expansion (New, PSCo)
				Rifle(Ute) – Story Gulch 230 kV (New, PSCo)
				Wheeler – Wolf Ranch 230 kV (New, PSCo)
				PSCo)
				Hoone-Walsenburg 230 kV (Tri-State)
				Boone – Lamar 230 KV Line (Tri-State)
				(***) Wilson Substation (New, PSCo)



Figure 2. Denver-Metro map of transmission projects in the 2016 Plan



Figure 3. Pueblo area map of transmission projects in the 2016 Plan

II. Transmission Planning in Colorado

A. Coordinated Planning

The Companies' transmission planning processes are intended to facilitate the development of electric infrastructure that maintains reliability and meets load growth. Because Colorado does not have a Regional Transmission Organization ("RTO"), each Transmission Provider ("TP") in the state is responsible for planning its own transmission system. To ensure that this process is as seamless and efficient as possible, the Companies participate in transmission planning at regional, sub-regional, and localized 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 WECC is the forum responsible for coordinating and promoting BES ("CCPG"). reliability in the entire Western Interconnection. As a result of the WECC territory's size (1.8 million square miles) and diverse characteristics, WECC members face unique challenges in coordinating daily system operations and long-range planning necessary to provide reliable electric service to customers in its footprint. The WECC includes committees that focus on transmission planning. The Transmission Expansion Planning Policy Committee ("TEPPC") prepares economic models and performs high-level assessments of transmission congestion and expansion needs on an interconnectionwide basis. The Planning Coordination Committee ("PCC") is responsible for preparing reliability models and performs assessments of the interconnection based on performance standards developed by the North American Electric Reliability Corporation ("NERC").

WestConnect is one of four planning "regions"² within WECC established for regional transmission planning to comply with FERC Order No. 1000, *Transmission Planning*

² The other three are Columbia Grid, Northern Tier Transmission Group, and the California Independent System Operator.

and Cost Allocation by Transmission Owning and Operating Public Utilities ("Order 1000"). At the end of 2015, WestConnect had 23 members, including 15 Transmission Owners, 5 Independent Transmission Developers, and one Key Interest Group. The WestConnect footprint includes 9 western states. One additional Transmission Owner is expected to join WestConnect in 2016. WestConnect includes 3 sub-regional planning groups ("SPGs"): CCPG, Southwest Area Transmission Group ("SWAT"), and Sierra Subregional Planning Group ("Sierra").



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

Many CCPG participants are involved in specialized work groups and subcommittees for example, the Conceptual Planning Work Group ("CPWG") and the TPL Studies Work Group—which are responsible for conducting technical, environmental, and cost studies for specific projects, focused geographic areas and/or expansion needs.

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

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



Figure 5. Transmission Ownership in the State of Colorado (2016)

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

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

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

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

B. Public Policy Issues

In addition to planning for load growth and reliability, Companies must consider proposed and enacted public policies. Two of the Companies, Black Hills and Public Service, are subject to the requirements of Colorado Senate Bill 07-100 ("SB07-100"), which requires Colorado's rate-regulated electric utilities to identify areas that have a high potential for beneficial resource development. These resources may include renewable, fossil fuel, and other generation types. The intent of this bill, which was

signed into law in 2007, is to continually evaluate the adequacy of the State's transmission infrastructure and plan improvements to meet the State's existing and future needs for electricity, a critical resource for Colorado's citizens and economy.

On or before October 31 of each odd-numbered year, Black Hills and Public Service are required to:

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

Black Hills and Public Service have initiated transmission planning activities to comply with the requirements of SB07-100 as part of the larger, coordinated planning efforts described above. As of 2016, Colorado's ERZs remain as they were defined in the 2007 and 2009 reports, created by consulting multiple sources of information as well as public feedback. As shown in Figure 6, Colorado's five ERZs are:

ERZ 1 (Northeast Colorado)

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

ERZ 2 (East-central Colorado)

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

ERZ 3 (Southeast Colorado)

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

ERZ 4 (San Luis Valley)

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

ERZ 5 (South-central Colorado)

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

In addition to the public policy requirements of SB07-100, all three Companies are subject to the requirements of the EPA's CPP and Colorado's CPP compliance plan which is being developed. The final rules related to CPP were published in the Federal Register on October 23, 2015, and the state of Colorado is in the early stages of formulating its plan for complying with CPP. The Companies are engaged with each other and relevant state agencies in the development of Colorado's CPP compliance plan which is due in September, 2016. While the Companies anticipate that aspects of the Colorado CPP compliance plan may impact transmission plans in the 10-year planning timeframe, those impacts are not yet known and it is premature to include in the 2016 Plan specific transmission projects related to CPP. The Companies will continue to coordinate with each other and stakeholders with respect to the transmission planning implications of CPP and expect to address this issue in the next Ten-Year Transmission Plan.



Figure 6. Map of SB07-100 Energy Resource Zones

III. Company Plan Narratives

A. Black Hills 10-year Plan Overview

1. Black Hills Service Territory

Black Hills Colorado Electric, a division of Black Hills Corporation, serves over 94,000 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. Black Hills Planning Process

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 7 shows a selection of needs that commonly give rise to projects within the Company's planning horizon.



Figure 7. 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:

Adequacy of each alternative to meet the specified need

- 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 constructable. 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 No. 890, 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

Black Hills' load growth has increased moderately over the past couple years, driven primarily by large industrial load expansions as well as some commercial load growth. The Black Hills projects included in the 2016 Plan largely reflect the continued strategy of infrastructure upgrades or additions to enhance reliability. Several of the projects were identified to accommodate customer load growth, and a single project was previously identified as part of a planned generation expansion at Pueblo Airport Generating Station. There is also one new project to incorporate wind generation at Rattlesnake Butte. Since most of Black Hills' projects are reliability driven equipment replacements or upgrades, the majority of best-cost considerations were narrowly focused.

In the 2016 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 and load service issues. Detailed project information can be found in Appendix D.

Since the filing of the 2014 10-Year Plan, Black Hills has completed four projects and removed them from the current list of significant planned projects: the new Pueblo Reservoir 115 kilovolt ("kV") substation, the Pueblo-Hyde Park-West Station 115 kV line rebuild, the Reader 115/69 kV transformer upgrades, the new Cañon City capacitor project. The West Station-Desert Cove 115 kV rebuild was placed into service in 2015 but was retained in the listing of planned projects for reference. Black Hills has identified ten new projects within the upcoming 10-year planning horizon that represent \$74.2 million in capital expenditures between 2016 and 2019. The projects were identified to increase reliability within Black Hills' network transmission system, to support voltage, and to meet the requirements associated with expected load growth and generation development. The reliability-driven projects are required under various NERC Reliability Standards to address anticipated system performance issues. The projects in this section were coordinated with stakeholders and neighboring entities to ensure the best solution is achieved while avoiding duplication of facilities.

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

Cañon City area

Four projects, shown in Table 2, address reliability concerns in the Cañon City area. Local load growth has resulted in the need for additional transformation capacity in the area, as well as additional local voltage support. A new transmission line into the area and new 115/69 kV substation will improve load service and operational flexibility.

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
*Portland 115/69 kV Transformer #1 Replacement	2017	\$2.5	Not Required
*Arequa Gulch Capacitor	2018	\$0.9	Not Required
West Station-West Cañon Transmission Line	2019	\$23.5	Application Pending
North Cañon 115 kV Substation	2019	\$9.9	Not Required

Table 2. Cañon City area projects included in the Black Hills 2016 10-Year Plan

* These projects are upgrades within the existing substation boundaries and therefore not included with other transmission projects in Figures 1-3 and Table 1. They are listed here for informational purposes.

The Black Hills planning process identified the solution for expected voltage concerns resulting from anticipated load growth at Arequa Gulch as the addition of a 12-MVAR 115 kV capacitor.

Additionally, a new 115/69kV transformer at Portland is planned to replace one of the two existing transformers. The smaller transformer may reach its thermal limit under certain operating conditions and will be replaced with a larger unit to provide the required capacity. Because both projects in this area were found to be in the ordinary course of business, CPCNs will not be required.

Load growth in the Cañon City area has led to reliability concerns following loss of the two transmission lines connecting that area to the Pueblo part of the Black Hills' system. Several options were considered, and the preferred solution was determined to be a new 115 kV transmission line from West Station to West Cañon. The new line would provide an additional connection to the area to maintain reliable service following the previously mentioned outage. The new connection also enables the future replacement of stressed transmission lines at a greatly reduced operational risk. Moreover, the project provides the added benefit of adding a 115 kV source at the existing North Cañon 69 kV substation. This will offload the existing

Cañon City transformer and add operational flexibility to the local 69 kV system. The new 115 kV source provides stronger backup service to the Cripple Creek area via the normal open 69 kV line for emergency situations. The scope of the West Station-West Cañon project is being coordinated with other entities for potential joint participation. This is being done to meet a wider range of system needs while minimizing the impact to the local landscape through the potential use of double circuit towers and utilization of existing transmission corridors when possible. The project was identified as an SB07-100 project in the 2015 study because it facilitates a larger resource injection from ERZ 4. Refer to the <u>2015 SB07-100 Study Report</u> for more information.

As load continues to grow throughout the planning horizon, the need for additional infrastructure will be reviewed as part of a long-term strategy for the Cañon City area.

Pueblo area

The central part of the Black Hills transmission system is in and around the city of Pueblo, Colorado.

Project Name	Est. In- Service Date	Cost (millions)	CPCN
West Station-Desert Cove Rebuild	2015	\$3.7	Not Required
Rattlesnake Butte Terminal Add.	2016	\$1.85	Not Required
Fountain Lake 115/69 kV Sub.	2016	\$12.8	Not Required
Baculite Mesa-Fountain Lake Rebuild	2016	\$3.0	Not Required

Table 3. Pueblo area projects included in the Black Hills 2016 10-Year Plan

Located between significant generation resources at Comanche and the Denver-Metro area load center, power in this part of the Black Hills system generally flows from south to north. This directional bias, as well as load growth in the area, has resulted in maximum utilization of individual transmission line segments of the three 115kV paths between the Reader substation on the southern end of Pueblo and West Station to the north. Planned generation expansion at Pueblo Airport Generating Station ("PAGS") required the rebuilding of the Baculite Mesa-Fountain Lake 115kV line as well as other minor terminal equipment upgrades. These solutions were selected based on their utilization of existing corridors through developed and populated areas, minimization of overall cost by avoiding new rights-of-way and substation expansions, and adequacy of the solution to resolve the identified needs.

One recently-completed project addresses issues related to the aforementioned south-to-north transfers from the West Station 115kV substation north toward the Western Area Power Administration ("WAPA") -owned Midway substation. The line connecting these substations may experience power flows in excess of its thermal limit under future system conditions. The West Station-Desert Cove 115kV line rebuild replaced the conductor on the first segment of this line with larger conductor in 2015. The Desert Cove-Midway segment of the same line is also under evaluation to replace limiting equipment in the future. Together these lines will provide a higher rating to accommodate larger power transfers to areas of need.

Planned substation/distribution projects in Pueblo include a new Fountain Lake 115/69/13.2kV distribution substation and a terminal addition at the Rattlesnake Butte 115 kV substation. The Fountain Lake substation will tap the Baculite Mesa-Northridge 115kV line. This project was identified as the preferred solution to address local distribution system needs in Pueblo. Increased transformer capacity is needed between the 115kV and 69kV systems at Reader and West Station. The replacement of the existing West Station transformers with larger units will eventually be required, and this project will allow load to be shifted off of those units to take the required outages. The Fountain Lake substation was initially planned to address distribution system issues by shifting load off of existing distribution lines that can approach their allowable capacity. Additional benefits to the local system include the ability to sectionalize the 69 kV system and operate it in a fully radial configuration, minimizing the impacts of unplanned outages.

The Rattlesnake Butte terminal addition will be completed to accommodate a new wind generator interconnection in 2016 and will consist of converting the exiting straight bus to a ring bus configuration.

Rocky Ford area

Rocky Ford is located between Boone and La Junta and is home to two projects in the 2016 Plan.

Project Name	Estimated In- Service Date	Cost (millions)	CPCN
Boone-Nyberg 115 kV Project	2016	\$10	Not Required
La Junta Area Upgrades	2017	\$6	Not Required

The first project in the Rocky Ford area includes 115kV transmission line upgrades between the Boone and Nyberg substations. The Boone-Nyberg 115 kV project includes the rebuilding of the existing Boone-DOT Tap-Nyberg line as well as adding a second circuit on double circuit structures. This project was identified to increase reliability to the Rocky Ford area following critical outages as well as to mitigate overloads on the existing line by adding capacity via the second circuit. The existing Boone-Nyberg line was a bottleneck between the Boone substation and the Pueblo area 115 kV system. The project utilized the existing right-of-way to the extent possible.

The La Junta Area Upgrades project consists of the addition of a second 115/69kV transformer at La Junta (Black Hills) and the replacement of the 115/69 kV transformer at Boone. The project will also add a 69 kV capacitor at Rocky Ford and address local terminal equipment limitations, adding reliability to the La Junta area. The project scope previously included a 115 kV connection to the Tri-State La Junta substation, but evolving circumstances resulted in the line being removed from the overall project scope.

Information concerning the specific Colorado projects included in the Black Hills 2016 10-year Plan is contained in Appendix D. Additional information and supporting documentation can be found at <u>www.blackhillsenergy.com/your-neighborhood/transmission-distribution/transmission-planning/colorado-electric-rule-3627</u>.

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, cost-based electric power to its 44 member cooperatives. As Tri-State's member cooperatives are spread across 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.

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

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

Tri-State's Member Systems create long-range plans and other work plans that they provide periodically to Tri-State's transmission planning department. When Member Systems' plans indicate the need for system upgrades or new construction, 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 Member Systems' requirements in a manner consistent with the immediate need and the long-term need in the context of the overall transmission system development.

Tri-State's contribution to the 2016 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 the following: Tri-State's Member Systems; transmission service customers; national and regional reliability organizations; and other transmission providers in Colorado and the region. Tri-State solicited input from a broad and diverse community of stakeholders including Member System owners, independent power producers, independent transmission companies, renewable energy advocates, environmental advocates,

and federal, state, and local government agencies in the areas potentially affected by the proposed transmission projects.

The result of this coordinated and comprehensive process is a 10-year transmission plan that includes transmission, distribution, and substation projects. Project summary information found in the following section and Appendix E focuses on the projects that involve the construction of new transmission lines in the state of Colorado. These transmission projects consist of some projects that are primarily intended to fulfill a load-serving need, some that are primarily intended to serve an identified reliability need, and some projects that are intended to provide transmission system congestion relief. 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 2016 Plan, it is important to recognize the key differences between Tri-State and other Colorado utilities. Tri-State is a generation and transmission cooperative formed and owned by its 44 member distribution cooperatives and public power systems located in four states: Colorado, Nebraska, New Mexico, and Wyoming. The territories served by Tri-State's Members cover a total of approximately 200,000 square miles. This large service area results in a load density that is significantly lower than that served by urban utilities. As a cost-based cooperative, Tri-State does not operate for profit and its Board of Directors, elected by the 44 Members, sets the rates charged to Tri-State's Members accordingly. Tri-State's primary mission is to provide its member cooperatives cost-based, reliable 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 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 2016 Plan includes some projects listed in the 2014 Plan.

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Big Sandy-Calhan	2021	\$52.9	Req'd
Burlington-Lamar	2020	\$53	Issued
Burlington-Wray	2016	\$40.2	Issued
Lamar-Front Range	TBD	\$900	Req'd
Lost Canyon Main Switch	2018	\$17.8	NR
Southwest Weld Expansion Project	2018	\$112	Issued

Table 5. Load serving projects included in the Tri-State 2016 10-Year Plan

Big Sandy-Calhan

In order to remedy current transmission service constraints in the Mountain View Electric Association ("MVEA") member service territory, which includes load-serving deficiencies and projected future growth that would overload existing facilities, Tri-State proposes to construct a 230 kV line from its Big Sandy substation (located northwest of Limon, Colorado) to the recently constructed Calhan substation. The primary purposes of the planned transmission line are threefold: mitigate projected overloads of Tri-State's 230-115 kV Fuller transformer, increase Tri-State's ability to deliver planned Tri-State generation in southeastern Colorado to its members int eh area, and provide a bulk transmission connection to the eastern side of MVEA's load area. The project is presently planned to be financed and constructed solely by Tri-State.

Burlington-Lamar

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

Burlington-Wray

The transmission system in northeastern Colorado has been forecasted to have an increased load in the coming years as well as increase in the development of renewable generation resources (namely wind). To accommodate the load growth and to increase the export capability for the existing and planned generation, Tri-State has decided to build a 230 kV transmission line between the existing Burlington and Wray substations. The planned line will complete a continuous 230 kV path through northeastern Colorado, substantially increase the limit of the load serving path through the area, and greatly improve the reliability of the transmission system in the area. The project is to be financed and built solely by Tri-State.

Lamar-Front Range

The Lamar-Front Range Project is a plan developed jointly through the CCPG to significantly improve load-serving capability, reliability, and potential resource accommodation in eastern and southeastern Colorado. The project could provide connectivity to the bulk transmission systems of Tri-State and PSCo, and provide strong "looped service" to areas with long radial transmission configurations. In concept, the project could create a transmission system capable of at least 2000 MW of new generation in eastern and southeastern Colorado.

This conceptual project identifies the transmission element additions that are needed to meet both companies' needs, including delivery of future generation to loads in the Denver and Front Range areas. The present conceptual project involves double circuit 345 kV transmission lines connecting Lamar to the Pueblo area and Lamar to the Burlington and Big Sandy substations. Transmission connections in the Pueblo area and connections from Big Sandy to Missile Site, Story, and Pawnee are also currently being evaluated.

Lost Canyon Main Switch

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

Southwest Weld Expansion Project

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

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Boone-Walsenburg	TBD	\$45	Req'd
Falcon-Midway	2019	\$5.6	NR
Pueblo West Tap Line Uprate	2016	\$0.5	NR
San Luis Valley-Poncha	2022	\$58	Req'd
Western Colorado Transmission Upgrade Project	2018	\$42	Issued

Table 6. Reliability projects included in the Tri-State 2016 10-Year Plan

Boone-Walsenburg

Presently, the loss of the Comanche-Walsenburg 230 kV transmission line results in severe thermal overloading on the 115 kV transmission system in the area. To prevent the overloading, a Remedial Action Scheme (RAS) is in place that trips the Walsenburg-Gladstone 230 kV line, resulting in the loss of load and reduced reliability in Northeast New Mexico.

To mitigate the need to trip the Walsenburg-Gladstone line, a second 230 kV transmission line is proposed to be built between the existing Boone Substation and existing Walsenburg Substation. The line will be routed from Boone to a location north of Walsenburg called Calumet, where it will then join with the existing Comanche-Walsenburg 230 kV line and continue to Walsenburg via a double circuit configuration. The transmission line will also increase reliability in the Pueblo, Colorado area and Northeast New Mexico in addition to foregoing the need for the RAS.

Falcon-Midway

The current Falcon-Midway 115 kV transmission line has a thermal rating of 95MVA, which leads to forecasted overloads by the summer of 2018 from an outage on Tri-State's 115 kV Falcon-Fuller line. In order to mitigate this problem, Tri-State is raising, moving, or rebuilding structures along the line to increase the overall line rating to 140MVA. The increased capacity will help serve Mountain View Electric Association's ("MVEA") customer load in the area. The project is being built and financed solely by Tri-State.

Pueblo West Tap Line Uprate

During Tri-State's annual transmission assessment, it was found that the Pueblo West Tap-West Station 115 kV line would become thermally overloaded after certain contingency/outages. In order to prevent these overload conditions, it was determined the best fix would be to uprate the existing line from 95MVA to 130MVA by rebuilding 0.3 miles of the existing transmission line.

San Luis Valley – Poncha 230 kV #2

New high-voltage transmission must be built in the San Luis Valley ("SLV") region of south-central Colorado to restore electric system reliability and customer load-serving capability, and to accommodate development of potential generation resources. Tri-State Generation and Transmission ("Tri-State") and Public Service Company of Colorado (Public Service) facilitated a study effort through the Colorado Coordinated Planning Group ("CCPG") to perform an evaluation of the transmission

system immediately in and around the SLV and develop system alternatives that would improve the transmission system between the SLV and Poncha Springs ("Poncha"), 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 to and operating it at 230 kV.

Western Colorado Transmission Upgrade Project

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

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Boone – Lamar 230 kV Line	TBD	\$65	Req'd
San Juan Basin Energy Connect Project	2018	\$129.5	Req'd

Table 7. Congestion relief projects included in the Tri-State 2014 10-Year Plan

Boone-Lamar 230 kV Line

The Boone-Lamar 230 kV line is a conceptual project that is intended to align with, but be a scaled down element of the much larger, conceptual Lamar Front Range project. The Lamar Front Range project was designed to accommodate as much as 2000 MW of new generation and envisions a substantial 345 kV transmission network in eastern and southeastern Colorado.

Several Tri-State studies have shown the need for an additional 230 kV transmission line between the Lamar and Boone substations under scenarios with increased generation in eastern and southeastern Colorado, but at levels less than what was considered by the Lamar Front Range project. Tri-State is currently constructing a new 230 kV transmission line between Lamar and Burlington, which will alleviate reliability issues and allow more generation in the region. However, if the needs of the region continue to grow, the next logical expansion of the eastern Colorado transmission system would be an additional 230 kV transmission line between Boone and Lamar.

San Juan Basin Energy

Southwest Colorado loads have the potential to grow by as much as 200 MW over the next ten years. Various transmission configurations were studied to serve the southwest Colorado load requirements. At present, the preferred alternative is a 230 kV transmission line originating at the Shiprock Substation 345 kV bus, going through a proposed new Kiffen Canyon Substation, in the Glade Tap area, and terminating at a new 230 kV substation called Iron Horse near Ignacio, Colorado. This configuration has the additional benefit of adding an independent second source to the Ignacio/Pagosa Springs area, significantly improving reliability.

Information concerning the specific Colorado projects included in the Tri-State 2016 10-year plan is contained in Appendix E. Additional information and supporting documentation can be found at:

http://www.tristategt.org/transmissionPlanning/

C. Public Service 10-year Plan Overview

Public Service is one of four electric utility operating companies of Xcel Energy Inc., which is an investor-owned utility serving approximately 1.4 million electric customers in the State of Colorado. Public Service serves approximately 75 percent of the State's population. Its electric system is summer-peaking with a 2015 peak customer demand of 6332 MW. The entire Public Service transmission network is located within the State of Colorado and consists of over 4500 miles of transmission lines. Colorado is on the eastern edge of the WECC transmission system, which constitutes the Western Interconnection. The Western Interconnection operates asynchronously from the Eastern Interconnection. The Public Service transmission system of its affiliate, Southwestern Public Service Company, since December 31, 2004 via a jointly-owned tie line with a 210 MW High Voltage Direct Current ("HVDC") back-to-back converter station. The Public Service retail service territory includes the Denver-Boulder metro area, as well as the I-70 corridor to Grand Junction, the San Luis Valley, Greeley, Sterling, and Brush.

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 their 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.

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. Consolidating and evaluating the next 10 years' worth of requirements, resources, and priorities has led to the development of Public Service's contribution to the overall 10-year transmission plan.

2. Public Service Projects

Table 8, below, lists the Public Service projects over 100 kV.

Table 8. Public Service 10-Year Tr	ransmission Plan
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Project Name	In-Svc	New Sub	New Trans	Upgrade	Cost (MIL)	Purp
Ptarmigan Substation	2014	Х			\$22.0	L
Arapahoe 90 MVAR Capacitor	2014			Х	\$3.5	R
Leetsdale 230/115 kV #2 Transformer	2014			Х	\$9.5	R
Malta 230/115 kV #2 Transformer	2014			Х	\$12.8	R
Midway 40 MVAR Reactor	2014			Х	\$2.5	R
Mt. Harris 138/69 kV Transformer #2	2014			Х	\$5.9	R
Waterton 40 MVAR Reactor	2014			Х	\$1.0	R
Rosedale Substation	2015	Х			\$10.0	R
Monfort-DCP Midstream 115 kV Transmission	2015		Х		\$3.5	L
Cherokee-Ridge 230 kV Transmission	2016			Х	\$5.5	R
Happy Canyon Substation	2016	Х			\$3.0	L
Rifle-Parachute 230 kV #2 Transmission	2016		Х		\$28.0	R,L
Avery Substation	2017	Х			\$16.0	L
Thornton Substation	2019	Х			\$30.0	L
Avon – Gilman 115 kV Transmission	2019		Х		\$20.0	R
Moon Gulch 230 kV Substation	2019	Х			\$2.0	L
Ault – Monfort 115 kV Transmission	2019	Х			\$8.0	R,L
Pawnee-Daniels Park 345 kV Transmission	2022		Х		\$180.0	R,G
Weld – Rosedale 230 kV	2022	Х			TBD	R,L
Rosedale – Milton 230 kV	2022	Х			TBD	R,L
Glenwood-Rifle 115 kV Transmission	TBD			Х	TBD	R,L
Lamar-Front Range Transmission	TBD		Х		\$900.0	R,G
Lamar-Vilas 230 kV Transmission	TBD		Х		\$90.0	G
Parachute-Cameo 230 kV #2 Transmission	TBD		Х		\$52.0	R,L
Weld County Expansion Transmission	TBD		Х		TBD	R,G
Rifle – Story Gulch 230 kV Transmission	TBD		Х		TBD	L
Wheeler – Wolf Ranch 230 kV Transmission	TBD		Х		TBD	L
Wilson Substation	TBD	Х			\$4.0	L
Bluestone Valley Substation	TBD	Х			TBD	L
Hayden-Foidel-Gore 230 kV	TBD			Х	TBD	R
San Luis Valley	TBD	Х			TBD	R,G

Key: R - Reliability, L - Load-serving, G - Generation/SB100,

Public Service's planned transmission projects can generally be placed in two basic categories. The first category consists of projects that are needed primarily for load growth or reliability purposes. These include both new projects as well as rebuilds or upgrades to existing transmission lines. As mentioned in the 2012 and 2014 filings, the Company's customer load is growing at a slower rate in the years since the 2008 recession. The slower load growth is due not just to continuing stagnation in the economy, but also due to increases in energy efficiency and demand-side management programs, changes in appliance efficiency, reductions in wholesale load now served by generation facilities installed in the region, and the increase in use of on-site photovoltaic energy systems. While transmission planners consider the potential for demands to return to historical rates, the general trend in this planning horizon is that project scopes are likely to contract and the timing for some projects may be delayed.

The second category consists of projects that are planned primarily to accommodate new generation resources. For Public Service, these projects tend to be associated with Senate Bill 07-100 and the Company's Electric Resource Plans ("ERP"). These projects include large transmission projects to access specific areas of the state that have the potential to host future wind, solar, and fossil generation facilities. The Company takes into consideration recent forecasts that indicate slower load growth and also where it stands with meeting its Renewable Energy Standard ("RES") requirements when approaching transmission planning. As a result, while the Company has developed plans to access each ERZ in Colorado, some projects do not have specific in-service dates. However, plans may continue to evolve incorporating consideration of other utilities' plans, Public Service load and resource needs, and the relative cost of new renewable resources and fossil generation. Although Public Service continues to acquire renewable energy resources, it has not done so at the same rate as in previous years. This is due in part to where Public Service stands in meeting RES requirements. Slower load growth also reduces the long-term requirements under the RES, which are tied to a percentage of retail energy sales. As a result of its 2011 ERP and subsequent 2013 All-Source solicitation, the Company added more renewable energy resources based on their cost-effectiveness. SB07-100 continues to be a driver for the

development of transmission plans that could deliver energy from beneficial resources. Presently, Public Service identified nine transmission plans through the SB07-100 process. Four of those plans have resulted in projects placed in-service. One project, the Pawnee – Daniels Park 345 kV Project, has received a CPCN from the CPUC, and is planned to be in service by 2022.

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

Following is a brief, narrative description of each Public Service project included in Table 1 and how it fits into the overall 2016 Plan. Information for the auxiliary projects shown in Table 8, as well as maps of the Public Service projects for each of the time-frames listed below can be found in Appendix F. Projects are arranged by their anticipated in-service dates.

Projects implemented since the 2014 Filing

This section describes the Public Service projects that have been placed in service since the 2014 10-Year Transmission Plan.

Upgrades to Existing Substations:

The following six projects consisted of upgrades or additions to existing substations. These are not shown on the transmission system maps.

- Arapahoe 90 MVAR Capacitor
- Leetsdale 230/115 kV Transformer #2
- Malta 230/115 kV Transformer #2
- Midway 40 MVAR Reactor

- Mount Harris 138/69 kV Transformer #2
- Waterton 40 MVAR Reactor

New Transmission and/or Substations:

Ptarmigan Substation

This project consisted of constructing a new Ptarmigan Substation by sectionalizing the existing Public Service Blue River-Dillon 230 kV line. This new substation serves the area around Silverthorne and parts of Dillon and is necessary to improve reliability for customers in Silverthorne, Dillon, Frisco and parts of Keystone. The project was placed in service in 2014 at a cost of approximately \$22 million.

Rosedale Substation

The purpose of the Rosedale Substation is to provide an additional 115 kV transmission source into the Greeley area to increase reliability to customers in the area. The project tapped into the existing WAPA Weld-Kersey Tap 115 kV line. The project was placed in service in 2015 at an estimated cost of \$10 million.

Monfort-DCP Midstream 115 kV Transmission

The Monfort-DCP Midstream Transmission Project consisted of a radial 1.5-mile line in Greeley that runs from the Public Service Monfort 115 kV substation to the DCP Midstream load-serving substation. The project was placed in service in 2014 at an estimated cost of \$3.5 million.

Planned Projects

Cherokee-Ridge 230 kV Transmission

This project converts the existing Cherokee-Arvada-Russell-Ridge 115 kV line to 230 kV operation for increased reliability. The project is under construction and is expected to be in service in 2016 at an estimated cost of \$5.5 million.

Rifle-Parachute 230 kV #2 Transmission Project

The Rifle-Parachute 230 kV Transmission Project is one of the transmission projects that Public Service has planned to address potential load growth on the Western Slope of Colorado. The other projects include the Parachute-Cameo 230 kV Transmission Project and the Bluestone Valley Substation Project. The Rifle-Parachute project will address the more pressing concern of serving new load growth in the Piceance Basin involving both natural gas developers and new retail customers. The anticipated demand in this area is projected to grow significantly due to natural gas extraction, which requires transmission service to electric motor-driven gas compression facilities.

The project consists of a new, second 230 kV transmission line between the existing Rifle and Parachute substations at an estimated cost of approximately \$28 million. The line will be about 20 miles long. A CPCN for the project was granted by the Commission in 2013 and the project has a planned in-service date of 2016

Happy Canyon Substation

This project consists of constructing a new Happy Canyon 115 kV substation tapping the existing Daniels Park-Castle Rock 115 kV line to allow Intermountain Rural Electric Association ("IREA") a delivery point for their customers in the area. The project has a planned in-service date of 2016 and an estimated cost of \$3 million.

Avery Substation

This project consists of constructing a new Avery distribution substation, which will be located in Weld County. The transmission source for Avery will be the Platte River Power Authority ("PRPA") Ault – Timberline 230 kV line. It is needed to serve the increase in customer distribution load in that area. The project has an estimated total cost of \$16 million and has a planned in-service date of 2017.

Thornton Substation

The Thornton (formerly Brantner) Substation Project consists of constructing a new substation in Thornton that will be used to serve the increase in customer distribution load in that area. This new substation will serve the City of Thornton in the north metro Denver area and provide back-up support to the existing Glenn and Washington distribution substations. The cost is estimated to be \$30 million and the project has a planned in service date of 2019.

Moon Gulch Substation

Moon Gulch is a new Distribution Substation to be built in either the City of Arvada or Jefferson County. The substation will tap the Plains End – Simms 230 kV line at approximately 1.5 miles from the Plains End Substation. It is needed to serve load growth in the Arvada area and will also provide backup service to the existing Eldorado and Ralston distribution substations. The Substation will be built to accommodate one 230/13.8 kV, 30/40/50 MVA transformer initially, but may be designed to ultimately accommodate three 230/13.8 kV, 30/40/50 MVA transformers and associated equipment. The project has a planned in service date of 2019 and has an estimated cost of \$2 million.

Avon – Gilman 115 kV Transmission Project

The Avon – Gilman 115 kV Transmission Project consists of constructing a new 10mile 115 kV line in Eagle County for reliability and to provide an alternate transmission source to Holy Cross Energy customers. The cost is estimated to be \$20 million and the project has a planned in service date of 2019.

Greeley Area Transmission

In the last few years, oil and natural gas companies have been drawn to Northeast Colorado. Load-serving entities such as Public Service and Tri-State have recognized the potential for increased demand for electricity due to oil and gas development. Public Service is also interested in ensuring reliability for its customers in the region, including the City of Greeley. Greeley is served by aging 115 kV and

44 kV transmission networks, and needs to ensure that the transmission system is planned and upgraded to accommodate reliability and load growth needs into the future.

Tri-State is developing the Southwest Weld Expansion Project ("SWEP"), which will initiate the transmission development in the region for serving oil and gas loads. The SWEP consists of 230 kV and 115 kV transmission that begins near Ft. Lupton, Colorado, travels east towards Hudson, and then heads north and ultimately connects to existing transmission a few miles south of Kersey. Tri-State received a CPCN for the project from the CPUC in 2014. Much of the SWEP transmission is planned to be constructed as double-circuit with 230 kV capability, with one circuit initially energized at 115 kV. The SWEP passes near or through Public Service customer service territory, and the Company has received requests for load interconnections in the area. The SWEP also provides opportunity to link with longer term transmission plans in northeast Colorado. As a result, Public Service plans to participate in SWEP. Tri-State has agreed to Public Service participation at a 40 percent share, and Public Service intends to seek CPUC approval for their participation in 2016.

Public Service has also developed transmission plans in and around the Greeley area that improve reliability, compliment the SWEP, increase the potential for resource accommodation, and establish a longer term plan for the northeast Colorado region.

The Weld – Rosedale and Rosedale – Milton 230 kV transmission projects are extensions of the SWEP transmission project that will allow Public Service to serve requests for oil and gas load service in the region, allow reliability improvements to the southern Greeley transmission system, and facilitate longer-term transmission plans in northeastern Colorado. The two projects consist of approximately 26 miles of new 230 kV transmission originating at the Tri-State Milton Substation (the northern 230 kV terminus of SWEP), tie into the Public Service Rosedale Substation,

south of Greeley, and terminate at the Weld Substation, east of Greeley. The Weld – Rosedale – Milton project has a planned in service date of 2022.

Prior to the Weld – Rosedale – Milton project, Public Service has planned a project through the north of Greeley that will enable it to begin replacing the existing antiquated 44 kV system with higher voltage 115 kV transmission. The project is presently referred to as the Northern Greeley, or Ault – Monfort Transmission Project. The project includes new transmission from the existing Ault Substation to a termination near the Public Service Monfort Substation. New load-serving substations would interconnect the transmission at or near the existing Public Service Ault and Eaton substations to allow the 44 kV loads to be transferred to the higher voltage network. Public Service intends to construct the new transmission at double-circuit with the capability to operate at 230 kV in the future. However, initial operation would be at 115 kV. The Ault – Monfort Project has a planned in service date of 2019.

Pawnee-Daniels Park Transmission

The Pawnee-Daniels Park 345 kV transmission project consists of building 115 miles of 345 kV transmission from the Pawnee Substation in northeastern Colorado to the Daniels Park Substation, south of the Denver-Metro area. The project will also result in a new Smoky Hill-Daniels Park 345 kV line. Additionally, the project will interconnect with the Missile Site 345 kV Substation. This project will accommodate additional generation in ERZ 1 and 2. The first 95 miles of the project would expand the planned Pawnee-Smoky Hill 345 kV Transmission Project, so that between Pawnee and Smoky Hill Substations, there would be double-circuit 345 kV transmission. One of the circuits would be the Pawnee-Smoky Hill 345 kV line. For the remaining 20 miles between Smoky Hill and Daniels Park 345 kV line. For the second portion of the Pawnee-Daniels Park 345 kV line. The second circuit would be a new 345 kV transmission line between Smoky Hill

and Daniels Park Substations. Public Service received a CPCN for the project in March 2015. Public Service requested an in service date of 2019, but the PUC ruled that the project should not be in service until 2022. The project is estimated to cost \$180 million.

Conceptual Plans

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

Wilson Substation

This project consists of constructing a new Wilson substation by sectionalizing the existing PRPA Horseshoe-West 115 kV line. The substation will be located in Loveland, Colorado. This new substation is needed to serve the increase in customer distribution load in that area. The project has an estimated cost of \$4 million. The 2014 Plan listed the project as having a planned in-service date of 2018. However, the project has been deferred indefinitely and implementation will depend on load growth in the area.

Bluestone Valley Substation

This project consists of constructing a new Bluestone Valley Substation that would tap Public Service's Rifle-Parachute-Cameo 230 kV line near Debeque. The new substation would provide additional load interconnections for customers in the area. Preliminary plans included a 230/69 kV autotransformer and about one mile of new 69 kV line. However, Public Service has been exploring other options for increasing the reliability in the area. Implementation of any project will depend in part on the local load growth.

Glenwood-Rifle Transmission

The project consists of upgrading the Glenwood Springs-Mitchell Creek-New Castle-Silt Tap line from 69 kV to 115 kV and new construction to reroute the Silt-Rifle line to the Rifle Substation at 115 kV. A portion of the rerouted 115 kV line will be double-circuited with the Rifle-Hopkins 230 kV line. The project is estimated to cost approximately \$37 million. The 2014 Plan listed the project as planned. However, implementation of this plan is uncertain at this time, and will depend on load growth around Glenwood Springs.

Hayden – Foidel Creek – Gore Pass 230 kV Transmission

This project consists of tying the Hayden-Gore Pass 230 kV line into the Foidel Creek Substation to increase reliability and improve voltage performance in the region. The project has an estimated cost of \$5.3 million. The 2014 Plan reported the project as having a planned in-service date of 2017. However, the project has been deferred and voltage issues will be mitigated by installing voltage control devices in the region.

Lamar-Front Range 345 kV Transmission

The Lamar-Front Range Study Group of the CCPG, which was formed in 2010, has considered additional transmission capability in southeastern Colorado, and has developed a new transmission plan that consists of approximately 400 miles of new 345 kV, double-circuit transmission and could deliver an estimated 2000 MW of new generation from energy resources near Lamar and Burlington to load centers along the Front Range. The current plan includes the following transmission components:

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

The proposed transmission interconnection and termination points were selected based on their proximity to the location of potential generation resource development, including renewable resources, or their ability to deliver such resources to serve some of the state's largest load centers. The Lamar-Front Range project, as presently envisioned, is estimated to cost approximately \$900 million. The planning studies have been completed, and project study reports are available. However, no decisions have been made with respect to implementation. Both Tri-State and Public Service continue to evaluate what strategies are most appropriate for moving forward (see additional narrative in the Tri-State section).

Lamar-Vilas 230 kV Transmission

The Lamar-Vilas project was evaluated as part of the Lamar-Front Range Plan. The Lamar-Vilas portion was planned to consist of approximately 60 miles of high-voltage transmission from the existing Lamar Substation to the existing Vilas Substation. The project would provide access to additional resources in ERZ 3, and could provide an opportunity for development of renewable energy facilities in Baca County. The project could not accommodate any new generation unless the Lamar-Front Range Transmission Project was also in place. As this project is dependent upon the Lamar-Front Range project, the Lamar-Vilas has the same status as that project.

Parachute-Cameo 230 kV #2 Transmission

The Parachute-Cameo 230 kV Transmission Project is an extension of the Rifle-Parachute Transmission Project. It is presently envisioned as a new, approximately 30-mile 230 kV transmission line that would connect the existing Parachute and Cameo substations on the Western Slope of Colorado. Preliminary analysis estimates the cost to be approximately \$52 million. Its primary purpose would be to increase reliability and to serve growing loads between Cameo and Debeque, including the Debeque and Una loads that are presently served by an aging 69 kV system. At this point, the project is beyond the 2020 timeframe. Public Service will continue to evaluate the customer load forecasts in the region and the costs associated with maintenance of the existing aging transmission facility, and develop a strategy for implementation accordingly.

Wheeler – Wolf Ranch

The project consists of a new radial 230 kV transmission line that would be used to serve customer loads in Garfield County. The line would be approximately 18 miles long and run between the existing Wheeler Substation to a new Wolf Ranch Substation. The line would also interconnect to the Middle Fork Substation. The 2015 Rule 3206 Report listed the project as having an in service date of 2018 and an estimated cost of \$17 million. However, the project has been deferred and implementation will depend on load growth in the area.

Rifle – Story Gulch Transmission

The project consists of a new radial 230 kV transmission line that would be used to serve customer loads in Garfield County. The line would be approximately 25 miles long and run between the existing Rifle (Ute) Substation to a new Story Gulch Substation. The project has an estimated cost of \$24 million, but the in service date is uncertain and implementation will depend on load growth in the area.

Weld County Transmission Expansion

Public Service has been contemplating upgrades to the transmission system in Weld County for several years. This originated around 2007 with a proposal for an Ault-Cherokee Project, which could provide transmission to ERZ 1 for SB100. Since the plan for that project originated at Ault and had the potential to impact a critical transmission path known as TOT7, or WECC Path 40, the project has a regional impact. Also, Public Service recognized the potential of any new plans in the area to help meet reliability and load growth north of the Denver-Metro area, particularly for the City of Greeley and the Weld County area. From 2012 to 2014, the plans were renamed to the TOT7 Transmission Expansion. Public Service announced that any proposed project would go through the WECC Project Coordination Review and Project Rating Review processes. In 2015, the planning effort was renamed to the

Weld County Expansion. This was done to try to alleviate confusion that some stakeholders had in believing that the primary focus was to improve the TOT7 transfer path. Now, the Weld County Expansion is more of a general planning term that includes the Greeley Area planning effort. The transmission planning takes place through the Northeast Colorado Subcommittee ("NECO") of the CCPG. The objectives of the NECO and the Weld County Transmission Expansion are to develop a coordinated transmission plan that will facilitate load growth, improve reliability in and around Greeley, provide access to potential resources in ERZ 1, and complement longer-term transmission projects in northeast Colorado.

San Luis Valley

Previous filings listed the San Luis Valley-Calumet-Comanche Transmission Project as a conceptual project that was designed to accommodate potential generation from ERZ 4 and 5 for delivery to customers along the Front Range, in addition to improving the transmission system in the San Luis Valley area of Colorado. As explained in Public Service filings to the Commission, including Rule 3206 and SB07-100 reports, the Company is no longer pursuing this project. However, as stated under the Tri-State 10-year Plan Overview, Public Service also recognizes the need for new high-voltage transmission in the San Luis Valley to restore electric system reliability and customer load-serving capability, and to accommodate development of potential generation resources. Public Service co-chairs the San Luis Valley Subcommittee of the CCPG, which has the objective to perform analyses and develop plans to improve the transmission system between the San Luis Valley and Poncha. The first phase of studies verify that, at a minimum, new 230 kV transmission San Luis to Poncha would be a first step to accomplish the objectives. A second phase of studies is planned for 2016, which will identify alternatives for transmission beyond Poncha to enhance reliability and generation export potential from the San Luis Valley to the Front Range. (Also see the narrative regarding SLV in the Tri-State section).

Information concerning the specific Colorado projects included in the Public Service 2016 10-year Plan is contained in Appendix F. Additional information and supporting documentation can be found at:

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

http://www.rmao.com/wtpp/psco_studies.html

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

IV. Projects of Other CCPG Transmission Providers

In addition to the projects planned by Black Hills, Tri-State, and Public Service contained in this 2016 Plan, a thorough understanding of all transmission projects planned in Colorado requires consideration of projects planned by other utilities and TPs. Information related to such projects is available through WestConnect and associated project summaries are contained in the following appendices:

Colorado Springs Utilities

Information concerning the specific Colorado projects included in the Colorado Springs Utilities Plan ("CSU") is contained in Appendix G.

In the 2014 Plan, project information was also provided for Platte River Power Authority, and WAPA. These entities did not have any updates or significant improvements for this 2016 Plan.

V. Stakeholder Outreach Efforts: Rule 3627(g)(l)

Per Rule 3627(g)(I), "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." The following sections summarize each Company's approach to stakeholder outreach and participation pertaining to Rule 3627. Processes specific to the stakeholder input directives of FERC Order No. 890 are discussed in Section V.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 that 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 are also 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 meetings were held in 2015 as part of Black Hills' annual TCPC process. Meeting notifications were publicly posted on the calendar on the WestConnect web site, announced at the CCPG meetings and posted on Black Hills' OASIS web page.

Black Hills' Q1 stakeholder meeting is more educational in nature and was held in Pueblo on March 20, 2015. It served the purpose of presenting the transmission planning process to stakeholders, describing the scope of the 2015 assessment, reviewing the current 10-Year Transmission Plan and soliciting feedback on the study scope, the stakeholder outreach process and potential alternatives to the projects within the 10-Year Plan. The meeting was held via web and phone conference to promote increased attendance. The meeting included an invitation to attend the subsequent quarterly meetings under the existing study process.

Black Hills' Q2 stakeholder meeting was held on June 17, 2015 via web/phone conference to review the data submittals for the computer-based transmission system model and obtain stakeholder approval on the final study scope.

Black Hills' Q3 stakeholder meeting was held on October 8, 2015 via web/phone conference to present initial study results and identified system needs. The results of the Senate Bill 07-100 report were also presented.

Black Hills' Q4 stakeholder meeting was held on December 16, 2015 via web/phone conference to present additional study results and project alternatives to address identified system needs. Study results and recommended project alternatives will be compiled into a report for final stakeholder review prior to the Q1 2016 stakeholder meeting. A similar stakeholder outreach process was utilized for the 2014 TCPC study cycle.

A limited number of stakeholders did attend the quarterly meetings. The stakeholder meetings produced some good dialog on specific projects and suggestions for process improvement, primarily adding as much detail as possible regarding projects and their drivers. 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 2015 or earlier Black Hills TCPC planning processes, including meeting notices, notes, presentations and contact information, refer to the Stakeholder Outreach folder on the WestConnect web site at:

www.blackhillsenergy.com/your-neighborhood/transmission-distribution/transmissionplanning/colorado-electric-rule-3627.

Stakeholder outreach information is also available in the Transmission Planning folder on the Black Hills OASIS at:

http://www.oatioasis.com/bhct

B. Tri-State Outreach Summary

Tri-State performs transmission planning-related stakeholder outreach as a standard part of its day-to-day business consistent with its policy of planning in an open, coordinated, transparent and participatory manner. This outreach encompasses various efforts including: Rule 3627 specific meetings and stakeholder communications;

FERC Order No. 890 specific meetings and communications; project-specific meetings and communications; and CCPG participation.

As described in Rule 3627(g)(I), stakeholders include federal, state, county, and municipal government agencies as well as other non-governmental organizations and individuals having an interest in the transmission planning process. Tri-State identifies potential governmental stakeholders based generally on a five-mile area surrounding proposed transmission facilities. Federal agencies in the areas of the transmission projects included in Tri-State's 2016 Ten-Year Transmission Plan include the Bureau of Land Management, the U.S. Forest Service, the National Park Service, and the Department of Defense. Potentially interested state agencies include the Colorado State Land Board and associated Stewardship Trust Lands, and the Colorado Division of Parks and Wildlife. Outreach to county and local governments typically includes communications to relevant elected officials as well as administrators, managers, and land planning, economic development, and legal staffs. In some instances, Tri-State's governmental outreach also included agencies such as parks and school districts.

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

In 2015, Tri-State hosted two transmission planning-related stakeholder outreach meetings in connection with development of the 2016 Ten-Year Transmission Plan. The first meeting was on March 18, 2015, and provided a summary of new information related to Tri-State's ongoing transmission planning activities as well as updates on current projects and coordination with CCPG's long range transmission planning efforts.

This meeting also constituted Tri-State's FERC Order No. 890 stakeholder meeting and provided an opportunity for stakeholders to provide input in connection with all of Tri-State's long range transmission plans. All such input and relevant alternatives were considered and included in the appropriate biennial transmission plans submitted to the Colorado Public Utilities Commission pursuant to Rule 3627.

The second stakeholder outreach meeting was held on November 20, 2015. This meeting did not introduce new information as long-term plans typically do not change within the short period between outreach meetings. Rather, this meeting provided an additional opportunity for continued stakeholder participation in the transmission planning and input with regard to Tri-State's long range transmission plans. Input received at this meeting was either considered in connection with Tri-State's 2016 Ten-Year Transmission Plan or will be considered in connection with the development of future ten-year plans developed pursuant to Rule 3627. No alternatives were proposed at this meeting.

In addition to these larger stakeholder meetings addressing system-wide and Coloradospecific 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 invitation lists, attendees, questions and comments received together with Tri-State's responses thereto, and relevant presentations can be found at:

http://www.tristategt.org/transmissionPlanning/Stakeholder-outreach.cfm

Additional transmission planning information is available at:

http://www.tristategt.org/TransmissionPlanning/.

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

http://www.westconnect.com/planning_ccpg_stakeholder.php

Tri-State confirms that, as required by Commission Rule 3627(g)(V), this 2016 Ten-Year Transmission Plan is available to all government agencies and other stakeholders through Tri-State's Transmission Planning website at:

http://www.tristategt.org/transmissionPlanning/puc3627_TransmissionProjects.cfm

Tri-State has informed all stakeholders of the availability of the 2016 Ten-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, other stakeholders including organizations and individuals representing various interests that have indicated a desire to participate in the planning process shall also have an opportunity for meaningful participation. Under the rule, Public Service is required to actively solicit input from the appropriate government agencies and stakeholders to identify alternative solutions. The following is a synopsis of the outreach that the Company performed relevant to this rule.

Rule 3627 Webinars

The Company developed an informational PowerPoint presentation that included information on the long-range plans developed as part of Rule 3627. Two hour-long webinars were held on Friday, August 14, 2015 and Wednesday, August 26, 2015, which were designed to give stakeholders the option of participating and commenting on transmission plans, either in person (at the Xcel Energy offices in Downtown Denver) or via Internet. An email invitation with exact verbiage can be provided at the request of the Commission.

More than 700 individuals representing the following stakeholder groups—including all state legislators in both the House and Senate—received invitations to both webinars:

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

Invitations were also sent to the CCPG's distribution list, which includes representatives from other utilities including Black Hills, WAPA and Tri-State, as well as stakeholders representing environmental interests, consulting firms, law firms, and other individuals and groups. Local government elected officials including county commissioners in counties which could be impacted by projects in the 10-year plan were also invited along with local planning office representatives, and other staff officials from local governments and agencies. Because routing has not been started on most of these

projects, which were still in the planning phase, individual landowners who might be impacted could not be identified.

Information on Xcel Energy's Transmission Projects in Colorado was provided to all invitees via a link in the email, but since then the web address was redirected to the following:

http://www.transmission.xcelenergy.com/Projects/Colorado

An announcement was posted on the Xcel Energy website in July 2015 providing notice of both webinars. The presentation from the webinars was posted to http://www.xcelenergy.com/Community/Events_& Presentations/Colorado_PUC_Rule_3627_Outreach_Meetings following the August 14th meeting and communicated to all invitees. A copy of the email's exact verbiage can be provided at the request of the Commission.

Attendance at the August 14, 2015 session included 9 in-person attendees external to the Public Service Transmission organization and approximately 20 webinar attendees.

Attendance at the second webinar was 14 in-person attendees external to the Public Service Transmission organization and more than 20 webinar attendees, although an actual count was difficult to gauge as participants dropped and added during the course of the presentation. Since self-identifying was optional, it was not possible to know if new people were added or if connections had been lost to some attendees and they opted to re-connect during the webinar.

The PowerPoint presented at both sessions consisted of three basics parts. Because the level of knowledge surrounding transmission and transmission planning of the attendees was not known, part one provided an overview of electric transmission to acquaint attendees with basic information about how the system works and what constitutes the transmission system. Part two covered the transmission planning process, provided an overview of how and why planning is done, and outlined the many factors that are considered when developing plans. Part three reviewed all projects included in Public Service's 10-Year Plan.

Public comment from these webinars covered a wide range of topics. Prior to the webinars the OCC submitted thirty questions & variety of comments to Public Service. Public Service provided responses to those comments in September 2015. The comments and associated responses are provided in Appendix H. Following the webinars, a letter was received from Alpern Myers Stuart LLC on behalf of the Interwest Energy Alliance. It included comments to promote some of the planned developments. In addition, The Town of Timnath sent Public Service a resolution regarding the Avery Substation Project.

However, no alternatives were provided by attendees during either session, and to-date there has been very little feedback received via any other channel.

FERC Order 890 Stakeholder Meetings

Prior to the ratification of Rule 3627, the Company facilitates two open stakeholder meetings per year to meet the requirements of FERC Order 890. The meetings are held in the first and fourth quarter every year at the Xcel Energy office in Denver, and the content is very similar to that presented in the Rule 3627 webinars. In the last two years, FERC Order 890 meetings were held on March 27, 2014, December 5 2014, April 3, 2015, and December 17, 2015. At the December 2015 meeting, and going forward, Public Service will likely take a similar approach as Tri-State, where the 3627 and FERC Order 890 meetings will simply be referred to as open stakeholder meetings that will meet the objectives of both rules.

PROJECT-SPECIFIC OUTREACH

Pawnee-Daniels Park

Public Service proposes to construct a new, double-circuit 345 kV transmission line to connect the existing Pawnee Substation near Brush, Colorado, to the Daniels Park Substation south of the Denver metro-area. The 125-mile project is part of Public Service's Senate Bill 07-100 portfolio of transmission plans and is a critical component

of the Colorado long-range transmission plan. The Pawnee-Daniels Park project will relieve transmission constraints and accommodate new generation resources in ERZ 1 and 2.

Public Service's outreach efforts began in July of 2013 when the Company started meeting with various residents, non-governmental organizations, elected officials, Homeowners Associations ("HOAs"), senior planning staff and other stakeholders.

During the week of March 17th 2014, the Company hosted a series of large scale open house meetings at the following locations:

Monday, March 17, 2014; 6-8pm Parker Arts Culture & Events Center (PACE), Parker, Colorado

Tuesday, March 18, 2014; 4-6pm Heritage @ Eagle Bend Golf Clubhouse, Aurora, Colorado

Wednesday, March 19, 2014; 6-8pm Highpoint Church, Aurora, Colorado

Thursday, March 20, 2014; 6-8pm The Wildlife Experience, Parker, Colorado

Over 6,000 invitations to the open houses were mailed out to residents within ¹/₄ mile of the existing corridor as well as all the other stakeholders that were contacted as part of the Company's public outreach efforts.

Notification of the open houses was posted in the following publications leading up the meetings: Aurora Sentinel, Parker Chronicle, Douglas County News Press and the Aurora and Douglas County Your Hub sections of the Denver Post.

Information provided at the open houses included project overview, need, resource planning, siting and permitting, transmission design, EMF, property values, undergrounding, comment forms and a variety of maps and figures. All of the

information presented at the open house meetings was made available and posted to the project website:

(<u>http://www.transmission.xcelenergy.com/Projects/Colorado/Pawnee–Daniels</u>), which is continually updated as new developments occur. The public is also able to leave comments about the project on the project website.

A project hotline was also established for the project to gather public comments (303.318.6307)

After the open house meetings, Public Service engaged in several discussions and meetings with opposition group, Halt the Power Lines, to address their concerns with the project.

A CPCN application to the PUC was submitted on March 28, 2014 with a hearing scheduled in front of the Administrative Law Judge ("ALJ") on September 9th 2014. Prior to the hearing, the ALJ decided to hold a public comment hearing in response to the opinion letters received by the public. The public comment hearing was held on July 23, 2014 at the Parker Arts and Cultural Events Center. Here, the public were able to voice their concerns and opinions of the project.

Colorado Office of Consumer Council ("OCC") Comments

The Office of Consumer Council intervened in the CPCN process for Pawnee – Daniels Park project. Nevertheless, staff of the OCC also chose to use the CCPG as a forum for expressing their objections to the project and also provided comments. In November 2014, the OCC submitted a comment, and a response was provided in January 2015. Appendix I includes the comment and response, using the CCPG Stakeholder Process.

The Colorado PUC approved the CPCN for the Pawnee – Daniels Park Project in March of 2015.

Routing Comments

In response to the public comments regarding other options for the transmission line route, the Company went out and reviewed alternative routes for the transmission line. Routes have been narrowed down and will be analyzed in a formal siting study. Alternative routes were shared with the public at another series of open house meetings held on September 29, 30 and October 1, 2015 in order to obtain further comments on the routes.

Over 8,300 direct mail pieces were sent out to residents within ¼ mile of the existing corridor as well as the alternative routes and included all the other stakeholders that had been contacted as part of the Company's public outreach efforts. Newspaper ads ran during the week of 9/14 and 9/21 and the Company's social media team made targeted notifications throughout the project area. A total of 475 people attended the open houses which were held in the following locations:

Tuesday, September 29, 2015; 6-8pm Parker Fieldhouse, Parker, Colorado

Wednesday, September 30, 2015; 6-8pm Wildlife Experience, Parker, Colorado

Thursday, October 1, 2015; 6-8pm Heritage @ Eagle Bend Golf Clubhouse, Aurora, Colorado

Comments from the open houses will be summarized and included in the Company's local land use permit applications to be filed in 2016.

Avery

Public Service is proposing to construct the Avery Substation and Transmission Line project. The new Avery Substation will enable the Company to serve existing and new load in the vicinity of Timnath, Severance and Windsor caused by growth of these communities along the I-25 corridor. Avery Substation will assist in providing back up to

the existing Cobb Lake and Windsor Substations, which are reaching their capacity. It also will provide reliability to our existing and future customer load. The project consists of a new electric distribution substation, an associated overhead double-circuit 230 kV electric transmission line and overhead distribution feeder lines near the towns of Windsor, Severance and Timnath, Colorado. Power for the proposed half mile to 3 mile 230 kV transmission line will be provided by interconnecting the existing PRPA Timberline-Ault 230 kV transmission line. Public Service is currently evaluating alternatives for this interconnection. This connection will supply the proposed Avery Substation with the electrical supply needed to power the distribution feeders serving the immediate communities.

At the first open house meeting the Company provided information, asked for the public's input and answered questions about the project. A series of graphic materials and other information was on display and a project website was made available at <u>www.xcelenergy.com/Avery</u>. In addition to submitting written comments at the open house, the public is allowed to provide comments and suggestions via the website. Direct mail pieces were sent out to 120 landowners and other stakeholders; a total of 15 attended the meeting. The meeting took place at the following location:

Wednesday, September 5, 2012; 4-7pm Windsor Recreation Center, Windsor, Colorado

Due to siting difficulties and a major lapse in time, Public Service decided to conduct another open house meeting to update the public and solicit further comments and suggestions. The project website stayed up to date during the lapse and people were again encouraged to provide comments and suggestions. Direct mail pieces were sent out to 140 landowners and stakeholders; a total of 8 attended the meeting. The format for the open house was the same as the first and was held at the following location:

> Thursday, May 29, 2014; 5-7pm Windsor Recreation Center, Windsor, Colorado

The Company will continue to seek public comment as alternative routes and substation sites are considered.

Thornton Substation

The Thornton Substation is a new distribution substation needed in the City of Thornton to provide reliable service and regulate voltage for a growing area. A series of meetings were held beginning in December, 2014. Two homeowners associations were met with to introduce the project and get feedback. An open house was held on December 3, 2015 for the general public at the Anythink Library in Thornton, Colorado. Over 1,300 invitations were mailed out to area residents around the preferred substation location. A total of 149 people signed in at the open house. In addition to the open house, individual meetings were set up with interested residents.

Additional outreach has included presentations to the Adams County Economic Development Council, the Adams 12 School District, local businesses, local public officials, and community organizations among others.

Public outreach is anticipated to continue into 2016 ahead of filing a local land use application with City of Thornton.

D. CCPG Outreach Summary

Stakeholder participation is also a central feature of the CCPG planning process. As described earlier, each TP has company-specific stakeholder outreach processes to afford interested parties the opportunity to review information and provide meaningful input on projects included in their respective 10-year transmission plans. Further, since many alternatives have the potential to span several TP networks and serve multiple needs, other forums for stakeholder participation are also available. These forums accommodate a broader perspective, allowing parties to provide meaningful input on a broader basis. They also provide stakeholders opportunities in addition to the company-specific outreach processes to participate in transmission planning. There are several venues for more stakeholder participation, including WestConnect and its sub-regional planning groups (CCPG, SWAT, Sierra).

To ensure stakeholders in Colorado have multiple opportunities to provide input and receive a broader perspective on the evolution of Colorado's transmission system, TPs also leverage the CCPG stakeholder input process in developing the 10-year transmission plan. 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 L as well as on the CCPG website here:

http://www.westconnect.com/filestorage/ccpg_stakeholder_input_process_041913.pdf

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

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

Once the CCPG chair receives the request, a determination will be made as to whether adequate information has been provided. The chair may contact the requester to ask for additional details. The chair will facilitate an ad-hoc review group ("Review Group") to review and categorize the request. The Review Group will determine:
- If the request is reasonable from a reliability planning perspective
- Who should be responsible? (CCPG or a smaller sub-group of CCPG; or should the study be forwarded to a larger group such as WestConnect or TEPPC)
- The likely scheduling for completing the analysis requested

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

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

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

If the Review Group determines that the request cannot be accommodated by CCPG or any TP, an explanation will be provided.

If the Review Group determines that the request can be accommodated, then the response will provide information as to the recommended logistics for how the request will be handled, including the responsible parties and a schedule for completion.

CCPG maintains a record of all comments and requests received, as well as the disposition. These records will also be posted on the CCPG section of the WestConnect website.

CCPG Pawnee – Daniels Park Stakeholder Input Process

As mentioned under the Public Service Stakeholder section, the OCC submitted comments to the CCPG. The Stakeholder input and the CCPG response are both included in Appendix I.

CCPG San Luis Valley Subcommittee Stakeholder Input Process

In the summer of 2014, Tri-State and Public Service came to a consensus to jointly perform a reliability study for the SLV area which meets both companies' objectives. At the 2014, 4th quarter CCPG meeting, Tri-State and Public Service presented the idea to the CCPG membership, and a study group was formed under the CCPG umbrella. The first conference call to kick off the subcommittee effort was held in December of 2014 and focused mainly on the first phase of the study effort - addressing the reliability portion of the study. The invitation was extended to all CCPG participants, and the study group followed the CCPG open stakeholder process for planning studies. At the beginning of the process, stakeholders were presented with a brief background of the SLV and the current issues that the system experiences.

There were four main objectives and needs identified by the SLV Subcommittee prior to the beginning of the study process. The goal was to identify and evaluate potential alternatives that would address the SLV transmission system limitations adequately. The objectives and needs to be addressed were:

- 1. Improve reliability
- 2. Increase load serving capability
- 3. Increase generation export capability
- 4. Allow for improvements to aging infrastructure

The first stakeholder call was followed by an open comment period for submission of alternatives for consideration. This comment period closed January 23, 2015. Closing of this comment period was followed by a second conference call on January 27, 2015. This second call reiterated the outlined objectives and needs and discussed the comments received during the comment period as well as the prior conference call. The comments pertaining to alternatives received during both the open comment period and two conference calls resulted in the eleven items below.

- 1. Restring San Luis Valley Poncha 69 kV on existing double circuit 230-69 kV structures to 230 kV and continue on new structures south to San Luis Valley.
- Restring San Luis Valley Poncha 69 kV on existing double circuit 230-69 kV structures to 230 kV and continue on new structures south to San Luis Valley. Rebuild remaining 69 kV line to 115 kV.
- Rebuild San Luis Valley Sargent Poncha 115 kV to 230 kV and Poncha San Luis Valley 69 kV to 115 kV
- 4. Rebuild San Luis Valley Poncha 69 kV to 115 kV with STATCOM
- 5. Rebuild San Luis Valley Poncha 69 kV to 115 kV with backup generation
- 6. New Poncha Malta 230 kV
- 7. New San Luis Valley Comanche 230 kV
- 8. New San Luis Valley Walsenburg 230 kV
- 9. New San Luis Valley Poncha 230 kV
- 10. New San Luis Valley Montrose 230 kV
- 11. New San Luis Valley Pagosa 230 kV

Some of the above alternatives were electrically equivalent allowing the subcommittee to reduce the number to a set of unique alternatives which could be studied to verify that they met the stated objectives. Alternatives 6, 7, and 8 were analyzed in previous studies, which are still relevant; therefore, the studies were not reproduced. Electrically speaking, alternatives 10 and 11 could also improve the reliability in the San Luis Valley. Nevertheless, the subcommittee declined to analyze them primarily because they would require the construction of new transmission lines across rugged mountainous regions. It was decided such lines would be so difficult to permit and build that they did not justify the effort required to model and analyze them. Taking the above into consideration, the eleven alternatives were narrowed down to seven.

- 1. Rebuild San Luis Valley Poncha 69 kV to 115 kV
- 2. Rebuild San Luis Valley Poncha 115 kV to 230 kV
- 3. New San Luis Valley Poncha 230 kV Line
- 4. Alternative 1 + Alternative 2
- 5. Alternative 1 + Alternative 3
- 6. Rebuild San Luis Valley Poncha 69 kV to 230 kV
- 7. New 230 kV San Luis Valley Poncha 230 kV Double Circuit Line

Other stakeholder comments did not outline specific alternatives, but were also addressed by the Subcommittee. They are listed below.

 Analyze locations/need for new substation(s) to accommodate export of 500 MW – 700 MW of new solar.

- 2. Consider that distributed generation, demand response, storage, and energy efficiency measures will reduce the need for 100 MW of transfer capacity over the next 20 years
- Consider proposed transmission and distribution infrastructure improvements will

 a) encourage utility-scale solar projects to be sited beyond Alamosa and Saguache Counties and b) facilitate DSM and other community-based technologies.
- 4. Evaluate if the existing 115 kV line can be re-conductored with bigger wire or bundled to increase the capacity of the 115 kV line.

Details on how the Subcommittee addressed the initial comments and the results of the studied alternatives can be found in the San Luis Valley Subcommittee Phase I Transmission Study report.

http://www.tristategt.org/transmissionPlanning/PUC3627_2016.cfm.

Also, both the OCC and Interwest Energy Alliance ("IEA") provided comments in response to a request for stakeholders to review a draft of the Phase I Transmission Study report. These comments were addressed by letter response.

All San Luis Valley Subcommittee Stakeholder input and the CCPG responses are included in Appendix J.

CCPG Northeast Colorado Subcommittee Stakeholder Input Process

The NECO Subcommittee provides a forum for coordinated planning of the transmission system that generally covers Weld, Morgan, Adams, Washington, Logan, Sedgwick, Phillips and Yuma counties.

A stakeholder (the OCC) provided formal input to the NECO Subcommittee on two occasions: June 26, 2015 and October 13, 2015. In response, CCPG formed an ad-hoc task force, consisting of members of the NECO Subcommittee, to review and categorize the input. Follow up meetings where held on September 17, 2015 and December 2, 2015 with the stakeholder.

A pared down list of alternatives to be considered by the NECO Subcommittee was developed through this process. The table below summarizes what the ad-hoc task force considered to be the remaining suggestions. The table also lists some of the potential benefits of the suggestions and how CCPG and the NECO Subcommittee will consider them in the future.

Alternative/Suggestion	Consideration
New Ennis – Rattlesnake Ridge 115 kV.	This addition would provide looped transmission service to Ennis Substation
	This may be considered by NECO in the future depending on load development at Ennis and the southern SWEP system
New Ennis – "Ennis South" 115 kV.	"Ennis South" is a new substation on the Pawnee – Ft. Lupton 230 kV line.
	This addition could provide a strong transmission source to Ennis.
	This may be considered by NECO in the future depending on load development at Ennis and the southern SWEP system.
New "Rattlesnake South" substation.	This substation would connect one or both 230 kV lines that run south of Rattlesnake Ridge and also tie to the SWEP lines.
	This may be considered by NECO in the future depending on load development on the southern SWEP system.
Convert the South Kersey – Kersey West 115 kV line to a double-circuit line.	This is being considered by Tri-State and Public Service.
New Neres – Box Elder – Willoby 115 kV line.	This addition would provide looped transmission service to Box Elder.
	This may be considered by NECO in the future depending on load development on the northern SWEP system.
Construct Ault – New Ault – New Eaton – New Pleasant Valley –	Replaces old 44 kV lines with new 115 kV and completes the 115 kV loop around Greelev

Table 9. Summary of stakeholder alternatives and suggestions to the NECOSubcommittee

Alternative/Suggestion	Consideration
Lucerne – Monfort as a double- circuit 115 kV line rather than a single-circuit line.	from the north to east. Also, with the closure of the Godfrey – Ft. Lupton line and the addition of SWEP, a double circuit line would essentially create two new paths from Ault to Denver.
	This will be considered by the NECO Subcommittee in the future.
Construct Ault – New Ault – New Eaton – New Pleasant Valley – Lucerne – Monfort as a 230 kV line rather than a 115 kV line.	Initially operated at 115 kV. This is consistent with the long-term plan that new load serving lines should be designed to be 230 kV capable.
	This will be considered the NECO Subcommittee in the future.

The Stakeholder input and the CCPG response are both included in Appendix K.

VI. 10-year Transmission Plan Compliance Requirements

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

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

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

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

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

Take the fairly broad environmental and societal concerns factor, for example. As its name implies, this factor considers how a project relates to the natural environment and

the public in general – both positively and negatively. In the context of transmission planning, this usually means:

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

For example, a planner may determine, by inspection, that a certain alternative is not practical because it would require a new transmission line over sensitive or exceptionally rugged terrain. This occurred in the CCPG San Luis Valley Subcommittee. The Subcommittee was tasked with evaluating the performance of alternatives to improve several deficiencies in the San Luis Valley transmission system. The biggest deficiency being that a single line outage can cause widespread outages to customers served by Public Service and Tri-State in Saguache, Mineral, Rio Grande, Alamosa, Costilla, and Conejos counties. One proposed alternative was to add a second 230 kV line to the San Luis Valley from either Montrose or Pagosa Springs. Electrically speaking, a new transmission line from either of these sources would likely improve reliability in the San Luis Valley. However, the subcommittee declined to analyze them in part because these alternatives would require the construction of new transmission lines across rugged mountainous regions. Given the potential costs, environmental impacts, and permitting and construction challenges, it was decided these alternatives did not justify the effort required to model and analyze them. More information on the work of the CCPG San Luis Valley Subcommittee can be found here: http://www.tristategt.org/transmissionPlanning/PUC3627 2016.cfm

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

- Spare equipment strategies, particularly for equipment that if failed, would take longer than 6 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 concerns were considered by the CCPG Western Slope Subcommittee in their 2014 *Western Colorado Transmission Study Report.* This study focused on the capacity of the western Colorado transmission system to accommodate present and future power transfers. The Subcommittee proposed and evaluated numerous potential transmission projects to facilitate higher transfer limits on TOT 2A, which is a limited transmission path. More information on this study can be found here: http://www.tristategt.org/transmissionPlanning/PUC3627_2016.cfm

Tri-State's Lamar-Burlington 230 kV project study provides an example of how planners consider generation congestion. Presently, there is more generation connected in the Burlington region than the existing system can accommodate, including renewable generation. The study determined that a new 230 kV line between Lamar and Burlington would relieve this congestion, provide environmental and societal benefits by accommodating renewable generation, and mitigate other issues.

http://www.tristategt.org/transmissionPlanning/PUC3627_2016.cfm

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.
- Considering the capability of new transmission alternatives to allow the injection and export of new generation resources.
- Considering the manner in which transmission alternatives align with longer term transmission strategies.

The CCPG San Luis Valley Subcommittee explicitly considered the first two factors in the 2015 San Luis Valley Study (see link above). Voltage Stability (P-V) analysis was performed for each studied alternative to compare their relative strength. This type of analysis is a common way to consider the relative ability of various transmission alternatives to serve future loads. The San Luis Valley Study also looked at the ability of each alternative to export new generation resources out of the San Luis Valley transmission system.

Tri-State's aforementioned Lamar-Burlington 230 kV project is a good example of planners considering how transmission alternatives are designed to align with longer term transmission strategies. In its CPCN testimony, Tri-State discussed how the Lamar-Burlington 230 kV project was an important first step to ultimately meet the objectives of larger, conceptual transmission projects in eastern Colorado.

http://www.tristategt.org/transmissionPlanning/PUC3627_2016.cfm

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, an preliminary evaluation of the aforementioned factors is typically performed as a screening process, with progressively more meaningful, in-depth evaluation occurring through the siting, permitting, and construction stages of development. Adherence to best-cost principles is formally reflected by each Company in its internal policies. For example, Tri-State policy requires careful consideration of:

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

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

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

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

All of the Companies participate in Commission dockets and initiatives, spending significant time and resources for Notices of Proposed Rulemaking, outreach efforts, meetings with Commission Staff and actively participating in initiatives in which the

Commission has expressed interest. In addition, the Companies participate with Commission Staff in the development of the conceptual long-range plans for Colorado's electric transmission infrastructure. The Companies individually meet with representatives of the Governor's Energy Office and take into account the suggestions of the Office. The Companies also meet with local governmental officials. These meetings transcend simple permitting requests, taking into account factors such as the economic development aspirations of the communities, cultural concerns of communities and the environmental aspects of transmission infrastructure expansion contemplated in various regions.

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

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

The NERC Reliability Standards can be found at:

http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction =United States

The WECC Criteria can be found at:

https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/TPL-001-WECC-CRT-2.1.pdf&action=default&DefaultItemOpen=1

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

1. Black Hills Reliability Criteria

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

- Transmission line loadings should not exceed 100 percent of continuous seasonal rating or the established equipment or operating limits.
- Transformer loading under system intact conditions should not exceed 100 percent of the normal rating.
- Transformer loading under contingency conditions should not exceed 100 percent of the emergency rating.
- Transmission bus voltage levels during normal conditions will be maintained between 0.95 p.u. and 1.05 p.u. of nominal system voltage.
- Transmission bus voltages during contingency conditions will be maintained between 0.90 p.u. and 1.1 p.u. of nominal system voltage.
- Following a disturbance, all generation units must remain in synchronism and voltage dips shall not drop below 0.70 p.u. at any load or non-load bus.

Additional details on the reliability criteria observed by Black Hills are provided on pages 15-18 of the Attachment K Methodology, Criteria, and Process Business Practices document, available at:

http://www.oatioasis.com/BHCT/BHCTdocs/BHCE_Method_Criteria_Process_Busin ess_Practice_04082010.pdf

2. Tri-State Reliability Criteria

In addition to fulfilling NERC and WECC standards and criteria, Tri-State observes its own set of internal criteria for planning studies. Tri-State performs an annual assessment of its regional interconnected transmission system elements utilizing simulation modeling cases created by WECC members. This annual assessment takes into account Tri-State's members in four states, with associated projects located in Colorado included in this plan. The modeling cases selected represent projected loads and transmission system topology for the year one through five horizon and the year six through ten horizon. These cases are selected to demonstrate system performance covering a range of forecasted demand levels and the most critical system conditions and study years. This analysis examines heavy and light loading scenarios, typically in cases modeling year one, year five, and year ten, unless other factors, such as known major system changes, dictate selection of another year. Cases created by WECC ensure that all projected firm transfers and established normal (pre-contingency) operating procedures are modeled, as well as existing and planned reactive power resources.

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

Additional information concerning Tri-State's reliability criteria is available in their Engineering Standards Bulletin at the following site: http://www.tristategt.org/transmissionPlanning/transmissionPlanDoc.cfm

Tri-State's reliability criteria can be updated periodically. The most current version at the time of this filing can be located directly at:

http://www.tristategt.org/transmissionPlanning/PUC3627_2016.cfm

3. Public Service Reliability Criteria

In addition to fulfilling NERC and WECC standards and criteria, Public Service observes internal company criteria for planning studies. Some of the internal criteria are as follows:

During system intact conditions, criteria are to maintain transmission system bus voltages between 0.95 and 1.05 per unit of nominal, and steady-state power flows below the thermal ratings of all facilities. Operationally, Public Service tries to maintain a transmission system voltage profile ranging from 1.02 per unit or higher

at regulating (generation) buses to 1.0 per unit or higher at transmission load buses. Following a single contingency, transmission system steady state bus voltages must remain within 0.90 per unit to 1.05 per unit, and power flows within 100% of the facilities' continuous thermal ratings. Also, voltage deviations should not exceed 5%. Transient stability criteria require that all generating machines remain in synchronism and all power swings should be well damped. Transient voltage performance should meet the following criteria:

- Following fault clearing for single contingencies, voltage may not dip more than 25 percent of the pre-fault voltage at load buses, more than 30% at non-load buses, or more than 20 percent for more than twenty (20) cycles at load buses.
- Following fault clearing for multiple contingencies, voltage may not dip more than 30 percent of the pre-fault voltage at any bus or more than 20% for more than forty (40) cycles at load buses.

In addition, transient frequency performance should meet the following criteria:

- Following fault clearing for single contingencies, frequency should not dip below 59.6 Hz for six (6) cycles or more at a load bus.
- Following fault clearing for multiple contingencies, frequency should not dip below 59.0 Hz for six (6) cycles or more at a load bus.

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

Per Rule 3627(b)(III), "Each ten year transmission plan shall demonstrate compliance with...[a]II 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 2016 Plan complies with all applicable NERC and WECC reliability standards, as well as other applicable legal and regulatory requirements, including the Colorado RES. For additional information on resource adequacy requirements, and resource requirements meeting the RES, please refer to pertinent proceedings and Commission decisions, as follows:

- Resource planning, 2013: Colo. Consolidated Proceeding No. 13A-0445E, serves as the primary proceeding for a number of related proceedings, including Black Hills' 2013 ERP Phase I Resource Determination of Need and Phase II Resource Acquisition, Black Hills' 2013 CPCN Application for 40 MW ("the LM6000") plant addition in Proceeding No. 13A-0446E, and Black Hills' 2015 CPCN Application for 60 MW Build/Transfer Wind Generating Project ("the Peak View Wind Project") in Proceeding No. 15A-0502E. Decision Nos. C14-0007 and C15-1182 granted Phase I and Phase II settlement agreements and CPCN authority for the LM6000 and Peak View Wind Project.
- <u>RES Compliance Plan, 2015-2017</u>: Colo. Proceeding No. 14A-0535E is Black Hills' application for approval of RES compliance plans for the years 2015 through 2017. Decision No. C15-1279 granted the application, approved the settlement agreement, and granted waiver of certain Commission rules.
- Interim On-Site Solar and Community Solar Garden Program, 2015: Colo. Proceeding No. 14A-0923E is Black Hills' application for approval, on an interim basis, of on-site PV solar and community solar programs outside of the RES Compliance Plan 2015-2017 in Proceeding No. 14A-0535E. Decision C14-1383-E granted the Company's application, and compliance tariffs were filed in Proceeding No. 14AL-1149E.

2. Tri-State Legal Requirements

Tri-State's 2016 Plan complies with all applicable NERC and WECC reliability standards, as well as other applicable legal and regulatory requirements including Company and member compliance with the Colorado Renewable Energy Standard ("RES"). The Colorado RES requires that 6 percent of retail energy sales be served by renewable generation in 2010, growing to 20 percent in 2020 and beyond. For the period 2015 through 2019, Tri-State's Colorado Member Systems are required to generate or cause to be generated electricity from eligible energy resources in an amount equal to at least six percent of their retail electricity sales. In addition, as a qualifying wholesale utility, the Colorado RES requires Tri-State to generate or cause to be generated at least 20% of the energy it provides to its Colorado Member Systems at wholesale from eligible energy resources in the year 2020 and thereafter. As the wholesale power provider for its Member Systems, Tri-State's 2016 Plan is developed to ensure that the necessary transmission system capabilities will be in place to meet both its Colorado Members Systems' and its own RES requirements.

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

http://www.tristategt.org/transmissionPlanning/PUC3627_2016.cfm

Tri-State is also subject to the requirements of the EPA's Clean Power Plan and Colorado's CPP compliance plan which is being developed. The final rules related to CPP were published in the Federal Register on October 23, 2015, and the state of Colorado is in the early stages of formulating its plan for complying with CPP. Tri-State is engaged with other Colorado electric utilities and relevant state agencies in the development of Colorado's CPP compliance plan which is due in September, 2016. While Tri-State anticipates that aspects of the Colorado CPP compliance plan may impact its transmission plans in the ten-year planning timeframe, those impacts

are not yet known and it is premature to include in the 2016 Plan specific transmission projects related to CPP. Tri-State also notes that, since it operates an interconnected, interstate transmission system designed to meet the needs of its Member Systems in Colorado, Nebraska, New Mexico, and Wyoming, its transmission system may be impacted as a result of CPP compliance plans developed in other states. Tri-State will continue to coordinate with other Colorado electric utilities, stakeholders, and other states in which it operates with respect to the transmission planning implications of CPP and expects to address this issue in its next Ten-Year Transmission Plan.

3. Public Service Legal Requirements

Public Service's 2016 Plan complies with all applicable NERC and WECC reliability standards, as well as other applicable legal and regulatory requirements including the Colorado RES. For additional information on resource requirements to meet the RES, please refer to Public Service online compliance reports available at:

http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/2010RES ComplianceReport_060111.pdf

http://www.xcelenergy.com/Company/Rates & Regulations/Filings/Colorado 2012 Renewable Energy Standard Compliance Plan

For additional information on the adequacy of Public Service system requirements in adherence with Commission rules, please refer to the ERP available at: http://www.xcelenergy.com/Company/Rates_&_Regulations/Resource_Plans

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

The Companies' transmission plans, as well as those of other Colorado transmission providers, are developed under the guidance of the CCPG. As stated in its charter, the CCPG is a planning forum that operates to assure a high degree of reliability in joint planning, development, and operation of the high voltage transmission system in the Rocky Mountain Region of the WECC. The CCPG operates in accordance with FERC Order No. 890, which sets forth principles for transmission planning. In keeping with the

principles of FERC Order No. 890, all transmission planning must include an open stakeholder process. Any stakeholder interested in the planning of the transmission system in the CCPG footprint can participate and obtain information regarding base cases, plans, and projects. The planning forums allow stakeholders to provide input or express needs or concerns related to the transmission system.

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 <u>Attachment K to its Open Access Transmission Tariff</u> ("OATT").

Additional information concerning Black Hills' FERC Order No. 890 processes can be found at:

- Attachment K Business Practices; Methodology, Criteria, and Process; and Economic Study Request Form: <u>http://www.oatioasis.com/bhct</u> →Transmission Planning
- General Stakeholder Information: <u>http://www.oatioasis.com/bhct</u>
 →Transmission Planning →TCPC

2. Tri-State Participation Strategy

Attachment L 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 2016 Plan, all projects included herein have been identified and developed through Tri-State's transmission planning process.

Attachment L to Tri-State's OATT is available on Tri-State's OASIS, by clicking on "Tariff & GIP" and then "Tariff" at the following link:

http://www.oatioasis.com/tsgt/

Attachment L to Tri-State's OATT can be updated periodically. The most current version at the time of this filing can be located directly at:

http://www.tristategt.org/transmissionPlanning/PUC3627_2016.cfm

3. Public Service Participation Strategy

For Public Service, the FERC Order No. 890 stakeholder process is included in the Xcel Energy Joint OATT Attachment R, available at the following website: http://www.oatioasis.com/PSCO/PSCOdocs/PSC-PRO-PSCo_Attachment_R.pdf

Additional information concerning the Public Service FERC Order No. 890 processes can be found at:

- Economic Studies: <u>http://www.oatioasis.com/psco/index.html</u> -> FERC 890
 Postings -> Customer Requests
- Stakeholder Meetings (General Info): <u>http://www.oatioasis.com/psco/index.html</u> -> FERC 890 Postings -> Stakeholder Meetings (This folder contains meetings agendas and presentations)

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

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

1) participate in a regional transmission planning process that produces a regional transmission plan

- 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
- remove from Commission-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities
- 4) improve coordination between neighboring transmission planning regions for interregional transmission facilities
- 5) participate in a regional transmission planning process that has a regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation
- 6) participate in a regional transmission planning process that has an interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions

WestConnect is one of four planning "regions"² within WECC established for regional transmission planning to comply with Order 1000. Public Service and Black Hills have designated WestConnect as their Order 1000 compliant planning regions. Tri-State has joined WestConnect as a coordinating transmission owner, which means it is not subject to all of the requirements under Order 1000 such as accepting binding cost allocation for regional transmission projects. The WestConnect planning process is described in Black Hills' and Public Service's OATTs (Attachment K and R respectively; links are provided above) as well in documentation found on the WestConnect website (http://www.westconnect.com/). The WestConnect website also houses information and announcements for many public planning meetings. WestConnect accepts stakeholder input throughout the planning process.

² The other three are Columbia Grid, Northern Tier Transmission Group, and the California Independent System Operator.

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 is also described in Black Hills' and Public Service's planning attachments of their respective OATTs.

WestConnect includes 3 SPGs: CCPG, SWAT, and Sierra.

VII.10-year Transmission Plan Supporting Documentation

A. Methodology, Criteria, & Assumptions

1. Facility Ratings (FAC-008-3)

NERC Reliability Standard FAC-008-3 requires that transmission and generation owners document the methodology used to develop ratings of their equipment. The standard requires that the transmission or generation owner supply its methodology to specific NERC registered entities upon request. FAC-008-3 also requires transmission and generation owners to establish facility ratings per the methodology established through FAC-008-3. Each transmission and generation owner has documented ratings for each of its facilities. The standard requires the transmission or generation owner to supply its facility ratings to specific NERC registered entities (i.e. associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s)) upon request. These documents are not publicly available and are not required to be per NERC standards. NERC Reliability Standard MOD-010-0 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 Annual Study Program as prescribed by the Data Preparation Procedural Manual.

a. Black Hills Ratings

Documentation of Black Hills' FAC-008-3 methodology is available at: <u>www.blackhillsenergy.com/sites/blackhillsenergy.com/files/bhc-fac-008-facility-</u>rating-methodology-08062015.pdf

b. Tri-State Ratings

Documentation of Tri-State's Facility Rating's methodology is available in their Engineering Standards Bulletin at:

http://www.tristategt.org/transmissionPlanning/transmissionPlanDoc.cfm

The most current version of Tri-State's Engineering Standard's Bulleting at the time of this filing can be located directly at:

http://www.tristategt.org/transmissionPlanning/PUC3627_2016.cfm

c. Public Service Ratings

Documentation of Public Service FAC-008 methodology is available upon request by contacting Mr. Thomas Green at Public Service.

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

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

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

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

 An organization requesting WECC base case(s) must either be a WECC member or they must execute the "Nonmember Confidentiality Agreement for WECC Data." b. Non-members may obtain the confidentiality agreement from WECC by sending a request via email to support@wecc.biz.

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

B. Load Modeling

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

1. Forecasts

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

a. Black Hills Forecasts

In 2013, Black Hills filed with the Commission its latest ERP, which included details on expected customer growth based on load forecast information submitted annually by network customers. The ERP, in conjunction with the network customer forecast updates, is used in the development of Load and Resource ("L&R") reports submitted to WECC on an annual basis. Once the L&R report is developed, this forecast is disaggregated to the respective transmission system load buses. There are two types of load buses: (1) a load bus where the load does not change over time (e.g. a single large industrial load bus); and (2) a load bus where the load changes over time (e.g. a residential load). Black Hills uses its knowledge of load characteristics along with historical loading observations to estimate the individual load bus data in time. The load bus forecasts are summed and compared to the WECC L&R report aggregate load

forecast. If the two forecasts do not match, the variable bus load forecasts are adjusted until the two forecasts match. Through this procedure the WECC L&R reports, including the assumptions in the latest ERP, are reflected in the transmission planning models used within the WECC footprint.

Details related to Black Hills' load forecast can be found beginning on page 19 of Black Hills' 2013 ERP in Colo. Consolidated Proceeding No. 13A-0445E (Exhibit FCS-1, Volume I ERP filed April 30, 2013). During the course of the 2013 ERP proceeding the load forecast was revised and subsequently approved by the Commission in Decision C14-0007. The revised load forecast is shown in Exhibit LS-3 to Rebuttal Testimony of Lisa Seaman filed with the Commission on October 10, 2013.

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" at the following link:

http://www.oatioasis.com/tsgt/

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 2014 load forecast data. Base forecast data for these plans is available in Appendix A of Tri-State's Electric Resource Plan Annual Progress Reports ("ERP/APR").:

http://www.tristategt.org/transmissionPlanning/PUC3627_2016.cfm

c. Public Service Forecasts

Public Service prepares two load forecasts a year. In addition to native load forecasts, Public Service receives forecasts from its wholesale customers, which it incorporates into the overall forecast. Transmission planners allocate the loads on a substation-by-substation basis, based on historical trends. More information can be found on page 2-98 of the 2011 Electric Resource Plan Vol. 2 at:

http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/Public Service-ERP-2011/Exhibit-No-KJH-1-Volume-2.pdf

2. Demand Side Management

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

a. Black Hills DSM

Details related to the effects of DSM savings estimates on Black Hills' load forecast can be found in Section 3.7 on page 18 of the 2013 Black Hills ERP in the Commission's E-filing system under Colo. Consolidated Docket No. 13A-0445E (Exhibit FCS-1, Volume I ERP).

b. Tri-State DSM

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

c. Public Service DSM

Public Service accounts for DSM through reduction in its load forecast based, in part, on the goals established by the Commission. In regards to how DSM impacts the Company's load and resources, see the Company's ERP found on page 2-66 of the 2011 Electric Resource Plan Vol. 2 – Technical Appendix available at:

http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/Public Service-ERP-2011/Exhibit-No-KJH-1-Volume-2.pdf

C. Generation and Dispatch Assumptions

Generator and associated equipment models are typically included in the WECC Annual Study Program base cases as required by the Data Preparation Procedural 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

For a listing of existing and planned resources included in planning studies, please refer to Section 6 of the Black Hills 2013 ERP, which is located in the Commission's E-filing system under Colo. Consolidated Docket No. 13A-0445E (Exhibit FCS-1, Volume I ERP). Black Hills may also include speculative generation (as identified in the <u>Generation Interconnection Request Queue</u>) in certain transmission studies as dictated by the study objective.

Black Hills typically utilizes an economic-based dispatch philosophy similar to the one found in Section 6.2 of the 2013 ERP, beginning on page 47. Depending on the objective of the transmission study being performed, the generation profile may deviate from an economic-based dispatch to a 'high-renewables' scenario or a high

energy import/export scenario to evaluate the impacts of that particular set of assumptions. The selected generation dispatch assumptions are identified in each transmission planning study report.

2. Tri-State Assumptions

Tri-State's transmission planning function receives generation assumptions from its network customers (Tri-State Power Marketing, Arkansas River Power Authority ("ARPA"), Municipal Electric Agency of Nebraska ("MEAN") and Public Service Company of New Mexico ("PNM") annually by October 1. These generation assumptions are utilized to ensure a sufficiently robust transmission system to meet network customers' needs over a 10-year planning horizon.

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

3. Public Service Assumptions

Public Service follows the WECC-established requirements and guidelines specific to modeling. Base cases reflect generation dispatch based on Public Service's internal procedures that take into account production costs, maintenance schedules, and other factors. Procedures include:

- If a generator will be modeled out of service, the Pgen & the generator status values should be set to zero. This is necessary to achieve correct reserve calculations
- Model generator planned outages with outage period of 6 months or more
- In general, high production cost generation plants are typically modeled out of service. If resources are needed, these units should be modeled in-service
- Typically, all Public Service combustion turbine generators are operated at full or near output to minimize the production costs

- Typically, the Public Service large coal-fired plants are base loaded (always operating at high output, 24/7). If generation adjustments are necessary, these generators should be adjusted last
- Hydro generation has net dependable seasonal ratings. Each seasonal rating reflects the average generation that can be continuously maintained over the duration of the daily peak period for the respective season. In winter, the daily period is approximately five hours long. All generators on-line should be producing MVARs. Generator bus voltage scheduling may be necessary if the generating unit is acting in a condensing mode (consuming MVARs)
- Wind generation is typically modeled at 12-75% of nameplate, depending on the study. Public Service is working with the Colorado Coordinated Planning Group to prepare a common methodology for representing renewable generation in planning studies.
- Solar generation is typically modeled at 65%

System changes, load transfers, and other topology changes are also coordinated through CCPG.

D. Methodologies

1. System Operating Limits (FAC-010)

System Operating Limits ("SOL") is defined in NERC Reliability Standard FAC-010-2.1 as the responsibility of the Planning Authority ("PA") to ensure reliable planning of the Bulk Electric System. SOL is required to be established per FERC standards but is not required to be publicly available.

a. Black Hills SOL

Black Hills has defined both Operational Criteria, which are limits for typical every day/normal operations, and SOLs, which are limits that are of an emergency nature and must be acted upon promptly to ensure facility ratings are not exceeded. Black Hills' SOLs are communicated to the Loveland Reliability Control

Center ("LRCC") 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:

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

b. Tri-State SOL

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

c. Public Service SOL

Public Service has one SOL for the TOT7, which is located north of the Denver metro area. The TOT7 studies are conducted annually. The results of those studies are available upon request.

SOLs are required to be established per FERC standards, but are not required to be publicly available.

2. Transfer Capabilities (MOD-001)

Available Transmission System Capability Methodology is available and posted per NERC Standard MOD-001:

http://www.nerc.com/files/MOD-001-1a.pdf

a. Black Hills TTC

Black Hills utilizes the Rated System Path Methodology for determining Total Transfer Capability ("TTC") and Available Transfer Capability ("ATC") for all Posted Paths and in all ATC time horizons. The determination of TTC is based on the maximum flow of a path while meeting all reliability criteria for Category B events. 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") on the Black Hills OASIS at:

http://www.oatioasis.com/BHCT/BHCTdocs/Attachment_1_Black_Hills_Corporation_ n_ATCID.pdf

b. Tri-State TTC

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

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

Tri-State utilizes TTC values based upon thermal facility ratings for all flow-limited paths that are owned solely by Tri-State. If the NERC MOD-029-1 requirement R2.1 simulation studies result in sufficient flow ability on a path segment to

determine a reliability limit, then the TTC on the ATC path segment is set to the simulated flow corresponding to the reliability limit while at the same time satisfying all planning criteria.

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

The ATCID provides for the documentation of required information as specified in the NERC MOD Standards and the NAESB OASIS Standards regarding the calculation methodology and information sharing of ATC specific to this TP. The ATCID for Tri-State is available on Tri-State's OASIS, by clicking on "ATC Information" and then "ATCID Document" at the following link:

http://www.oatioasis.com/tsgt/

The ATCID can be updated periodically. The most recent version of the ATCID at the time of this filing can be located directly at:

http://www.tristategt.org/transmissionPlanning/PUC3627_2016.cfm

c. Public Service TTC

Public Service's ATCID (MOD-001) is posted at the following link:

<u>http://www.oatioasis.com/PSCO/</u> → ATC Information

3. Capacity Benefit Margin (MOD-004)

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

a. Black Hills CBM

Black Hills does not implement CBM in the assessment of ATC. The Capacity Benefit Margin Implementation Document ("CBMID") for Black Hills is located at the following link:

http://www.oatioasis.com/BHCT/BHCTdocs/Attachment_1_BHC_CBMID.pdf

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)" at the following link:

http://www.oatioasis.com/tsgt/

The CBMID can be updated periodically. The most recent version of the CBMID at the time of this filing can be located directly at:

http://www.tristategt.org/transmissionPlanning/PUC3627_2016.cfm

c. Public Service CBM

Public Service's CBMID is located at the following link: http://www.oatioasis.com/PSCO/ \rightarrow ATC Information

4. Transmission Reliability Margin (MOD-008)

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

a. Black Hills TRM

The TRMID for Black Hills is located at the following link:

http://www.oatioasis.com/BHCT/BHCTdocs/Attachment_1_TRMID.pdf

b. Tri-State TRM

The TRMID for Tri-State is available on Tri-State's OASIS, by clicking on "ATC Information" and then "TRMID Document" at the following link:

http://www.oatioasis.com/TSGT/TSGTdocs/TRMID_6-23-11_v1-120120314104759.pdf

The TRMID can be updated periodically. The most recent version of the TRMID at the time of this filing can be located directly at:

http://www.tristategt.org/transmissionPlanning/PUC3627_2016.cfm

c. Public Service TRM

The TRMID for Public Service is located at the following links: <u>http://www.oatioasis.com/PSCO/</u> \rightarrow ATC Information

E. Status of Upgrades

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

F. Studies and Reports

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

http://www.westconnect.com/planning_ccpg.php

Additional Company-specific study and reporting resources are described below.

1. Black Hills Reporting

Public access to transmission market information, generator interconnection and transmission service requests, business practices, and other topics related to the Black Hills transmission system is provided on Black Hills' OASIS at:

http://www.oatioasis.com/bhct

Information on Black Hills' 2015 SB07-100 study process, including the final 2015 SB07-100 study report, was filed with the Commission in Docket No. 15M-0853E and can be found in the Commission's E-filing system under that docket number, and is also located at: www.blackhillsenergy.com/your-neighborhood/transmission-planning/colorado-electric-senate-bill-07.

Study reports supporting the projects in Black Hills' 10-year Transmission Plan are located at <u>http://www.blackhillsenergy.com/your-neighborhood/transmission-distribution/transmission-planning/colorado-electric-rule-3627</u>.

2. Tri-State Reporting

Planning studies and related reports for Tri-State transmission projects in Colorado are located at the following link:

http://www.tristategt.org/transmissionPlanning/puc3627_TransmissionProjects.cfm

3. Public Service Reporting

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

http://www.rmao.com/wtpp/psco_studies.html

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

http://www.transmission.xcelenergy.com/Planning/Planning-for-Public-Service-Company-of-Colorado
Public Service's SB07-100 2015 report is available at:

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

G. In-Service Dates

Information concerning the expected in-service date for each utility's facilities identified in the 2016 Plan and the entities responsible for constructing and financing each facility is contained in Table 1, Section III and Appendices A-F.

H. Economic Studies

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

1. Black Hills Economic Study Policies

Black Hills conducts economic planning studies through the procedures outlined in its <u>OATT Attachment K</u>.

Black Hills will accept requests for economic studies on an annual basis. Information on making a request is available in the <u>Attachment K Economic Study Request</u> <u>Form</u>. 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 study up to one economic study request that has been classified as local on a bi-annual basis. All economic study requests that have been classified as subregional or regional will be forwarded to the WECC TEPPC for inclusion in the WECC TEPPC Study Program.

2. Tri-State Economic Study Policies

Western Interconnection-wide congestion and economic planning studies are conducted by WECC-TEPPC in an open stakeholder process that holds region-wide stakeholder meetings on a regular basis. The WECC-TEPPC planning process is posted on its website (see www.wecc.biz). Tri-State participates in the regional planning processes, as appropriate, to ensure data and assumptions are coordinated.

3. Public Service Economic Study Policies

Public Service facilitates priority local economic planning studies for its transmission system, pursuant to the procedures in its OATT Attachment R. Regional economic planning studies shall be performed by the WECC TEPPC, pursuant to procedures posted on the TEPPC page of the WECC website.

Public Service's economic studies can be found at the following link:

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

→ FERC 890 Postings →Customer Requests.

2016 CPUC Rule 3627 Appendices

- Appendix A: Colorado Maps of 10-Year Transmission Plan Projects Implemented from 2014-post 2019
- Appendix B: Denver-Metro Map of 10-Year Transmission Plan
- Appendix C: Pueblo Area Map of 10-Year Transmission Plan
- Appendix D: Black Hills Project Summary and Project Sheets
- Appendix E: Tri-State G&T 10-Year Transmission Projects
- Appendix F: Public Service Company 10-Year Transmission Projects
- Appendix G: Colorado Springs Utilities 10-Year Transmission Projects
- Appendix H: OCC 3627 Comments & Responses
- Appendix I: CCPG Stakeholder Process for OCC Comments to Pawnee-Daniels Park 345kV Project
- Appendix J: CCPG Stakeholder Process for Comments to the CCPG San Luis Valley Studies
- Appendix K: CCPG Stakeholder Process for OCC Comments to the CCPG Northeast Colorado Studies ("NECO")
- Appendix L: Stakeholder Survey