Colorado Long Range Transmission Planning Study

Colorado Long Range Transmission Planning Group

Aquila Networks
Colorado Springs Utilities
Platte River Power Authority
Tri-State Generation and Transmission
Western Area Power Administration
Xcel Energy/Public Service Company of Colorado

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Appendices

I. Executive Summary

The Colorado Long Range Transmission Planning Group (CLRTPG) was initiated in January 2004 to jointly explore the potential for the development of a “back-bone” transmission network in the State of Colorado that could benefit all electric load-serving entities (LSE’s) in the state. Current forecasts predict that over the next ten years, the demand for power will grow 25% in Colorado’s Front Range. To meet such a demand, over 2,750 MW of new generation resources will have to be acquired and robust high-voltage transmission will be needed to convey the power to major delivery points. In February 2004, Public Service Company of Colorado (PSCo) announced its intention to pursue the development of a new 750 MW coal-fired generation facility at the Comanche Station in Pueblo (Comanche Unit #3). Since this was the only generation project planned with any degree of certainty, PSCo sought to design the transmission required for the Comanche Unit #3 in a manner that would meet the primary objectives of the CLRTPG.

The proposed transmission to facilitate the Comanche Unit #3 will consist of new double-circuit 345kV transmission between the Comanche Station and the Daniels Park Substation southeast of Denver. CLRTPG studies show and there was Group consensus that the Comanche – Daniels Park 345kV Transmission Project will be the fundamental first phase toward the development of a back-bone transmission system in the Front Range. The Project will establish 345kV transmission in the Front Range in a cost-effective manner and facilitate additional higher-voltage transmission development in the future.

Subsequent phases are anticipated to consist of additional 345kV transmission in a new corridor that would run from south to north in the eastern plains. The 345kV network could connect major southern substations such as Comanche, Boone, and Lamar to major substations in the north such as Daniels Park, Smoky Hill, and Pawnee. The CLRTPG is determined to continue to jointly examine the future of transmission development in Colorado.

II. Introduction

Over the next ten years, the demand for electric service throughout Colorado is expected to grow significantly. The growth is expected to be especially high within the PSCo service territory and particularly along the Front Range where forecasts predict a 25% peak demand growth between 2004 and 2014. LSE's within the state anticipate a significant number of new generation resources will be required to adequately meet the growing demand for electricity. The construction of additional high-voltage transmission lines will be essential in order to reliably transfer electric power from generation to load centers.

Transmission Planners must formulate strategies to develop and improve the transmission system in the state of Colorado to support the anticipated load growth and resource requirements. To help assure that those transmission additions complement the needs of all LSE's and future generation resources throughout Colorado, the CLRTPG was formed to jointly develop a ten-year regional plan for the implementation of high-voltage transmission in the Front Range of Colorado. The Group was formed as a sub-committee of the Colorado Coordinated Planning Group (CCPG), whose purpose is to facilitate open discussion and joint planning efforts for the transmission in the Rocky Mountain Region (primarily Colorado and Wyoming). An open invitation to participate in the CLRTPG was posted on the Rocky Mountain Area OASIS (RMAO)[1] in mid-December of 2003. The CLRTPG met for the first time on January 9, 2004[2] and included participation from:

- Aquila Networks (Aquila)
- Arkansas River Power Authority (ARPA)
- Colorado Springs Utilities (CSU)
- Platte River Power Authority (PRPA)
- Tri-State Generation and Transmission (TSGT)
- Western Area Power Administration, Rocky Mountain Region (WAPA)
- Xcel Energy/ Public Service Company of Colorado (PSCo)

The goal of the CLRTPG was to develop a long-range bulk transmission plan that would best fit the future needs of the State of Colorado given the anticipated load growth, collective knowledge of the transmission system and potential sites for new generation resources. The transmission plan should result in a robust "back-bone" transmission system that eliminates the often "piece-meal" approach to transmission. This was to be accomplished by developing a transmission system that will readily accommodate future generation development and optimize transmission additions. This plan will be submitted to the Colorado Public Utilities Commission (CPUC) as part of PSCo's required Least Cost Resource Plan filing on April 30, 2004.

[1] www.rmao.com; OASIS is an acronym for Open Access Same-Time Information System
[2] Meeting invitation is included as Appendix A

III. Study Methodology and Development

Generally speaking, the specific locations for future generation development are largely unknown. However, on October 31, 2003, PSCo publicly announced plans to develop a 750 MW coal-fired generating facility at either the existing Pawnee Generating Station near Brush, Colorado or the Comanche Generating Station, near Pueblo, Colorado. In February 2004, PSCo announced its decision to focus on the development of a 750 MW coal-fired generating facility at the Comanche Generating Station. In addition, PSCo has received several requests from independent power producers to study the interconnection of generating resources from 30 MW to 500 MW at various points of interconnection on PSCo's transmission system. Those requests are listed in the RMAO queue, and posted on its website. Other potential sites include previously studied prospective locations, such as the Southeast Colorado Coal Project. Also, some existing plant locations lend themselves to additional generation expansion.

A. Resource Needs

On January 20, 2004, the CLRTPG met to jointly develop three generation and transmission scenarios for additional study. Each entity first ascertained what its resource needs would be for the year 2014. Table 1 shows the resource needs submitted by entity. The group determined that a total of 2750 MW of additional generation resources would be needed, including a capacity reserve margin.[3] This number was derived jointly by the group and in particular by PSCo and their Resource Planning group in January 2004.

ENTITY	COLORADO ONLY RESOURCE NEED (MW)
PSCo	2226
TSGT	324
CSU	100
PRPA	100
Total	**2750**

Table 1 - Additional Front Range 2014 Resource Need

Table 1 was derived from a set of Loads and Resources (L&R) documents created for this study. The L&R sheets provide a summary of each LSE's capacity resource plans, reserve margins, and projected demands. The L&R sheets can be found in Appendix B.

Each individual LSE L&R balance sheet showed a resource need. The individual resource requirements were added together to achieve a total Colorado Front Range resource requirement. Some adjustments were made during the development of the L&R sheets. TSG&T made a 27 MW increase adjustment from 297 MW to bring their requirement to 324 MW, to bring the total resource need to 2750 MW. PRPA showed an adjustment of 12 MW from 88 MW to bring

[3] The reserve margin varied by entity.

their need to 100 MW. CSU adjusted their need from 214 MW to 100 MW to reflect some possible resources that may be added to their system before 2014.[4] This resulted in a total resource requirement of 2750 MW to meet the projected future demands and reserve margins.

Aquila and WAPA were not included in the Colorado resource needs table (Table 1). The Aquila peak demand loads were not shown as a PSCo responsibility in the PSCo L&R sheet for the 2014 models due to anticipated supply contract expiration in 2011. However, due to contract extension uncertainty, the Aquila loads were modeled as served from excess generation on the PSCo system (reserve margin capacity). WAPA loads were not included in Table 1 since the majority of the load in their control area consists of TSGT and CSU loads.

B. Generator Siting

The focus of the study was to evaluate transmission additions in the Front Range that would accommodate 2014 forecasted loads and potential future generation resources located in Colorado. All of the new generation resources were placed in the eastern half of Colorado. It is recognized by Colorado LSE's that the transmission path into the Front Range from the west (TOT 5) is limited and due to the geographic nature of the Continental Divide and National Forests, building new transmission from the west would be extremely difficult and expensive to site. Moreover, relatively few requests have been made in recent years for new generation in western Colorado to serve eastern loads. The transmission path from the north, TOT 3, is also limited. There have been numerous discussions and studies of alternatives over the years to increase its transfer capability, but there have been no commitments to build new transmission. Studies for this path are complex and time-consuming. The TOT 3 limit is dynamic which introduces more uncertainty into the amount of additional capacity that might be obtained and is necessary for economic evaluation by a prospective transmission provider. Therefore, in the interest of time and with prudent reasoning, the group focused on generation additions in the eastern half of the state. Given that the generation additions were within the TOT boundaries, the TOTs were only considered from the perspective of maintaining existing import capability. It is anticipated that the CLRTPG will evaluate the expansion of the major Colorado TOTs in future studies.

Many of the generation sites that were chosen for study were taken from the RMAO queue. For example, recent Generator Interconnection requests in the queue were used to choose sites such as 500 MW in Elbert County (GI-2003-2), 300 MW in Morgan County (GI-2003-1), 750MW at the Comanche substation (GI-2003-3) and 750 MW at the Pawnee substation (GI-2003-5). A Southeast Coal generator site with an output of 500-550 MW was chosen, which reflects the first phase of the Southeast Colorado Coal Project, studied in 2002 by TSGT and

[4] CSU has recently announced that the generation development assumed in the January L&R has been postponed.

participants. Also, PSCo has received transmission service requests from the Southwest Power Pool (SPP) region in the Eastern Interconnection to accommodate potential eastern generation resources being scheduled to the Western Interconnection. Any increase in schedules from the east would require an expansion of PSCo's High Voltage Direct Current (HVDC) Converter Station (210 MW) near Lamar, CO, planned to begin commercial operations on December 31, 2004. As a result of this interest, an expansion of the HVDC tie was assumed in some of these studies. A recent list of PSCo Generator interconnection requests is shown in Table 2.

GENERATION INTERCONNECTION REQUESTS
March 19, 2004

Queue Number	Date Received	Generation Type	Service Type	Location County/State	Interconnection Point Station or Line	Net Plant Max MW Sum	Net Plant Max MW Win	In-Service Date	Comments/Status/Reason not Completed
GI-2003-1	10/21/2003	Wind	Network Resource	Morgan Co., CO	Pawnee Substation	300	300	12/1/2006	Feasibility Study complete
GI-2003-2	11/3/2003	Coal	Network +Energy Resource	Elbert Co., CO	Smokey Hill-Pawnee 230kV line	500	500	6/1/2008	Feasibility Study complete System Impact Study underway
GI-2003-3	11/7/2003	Coal	Network Resource	Pueblo Co., CO	Comanche Substation	750	750	10/1/2009	System Impact Study underway
GI-2003-4	11/11/2003	Wind	Network +Energy Resource	Laramie Co., WY	Ponnequin Substation	30	30	Q2:2004	Feasibility Study complete
GI-2003-5	12/29/2003	Coal	Network Resource	Morgan Co., CO	Pawnee Substation	750	750	10/1/2009	Request withdrawn 2/20/04
GI-2004-1	1/19/2004	Wind	Network +Energy Resource	Morgan Co., CO	Story Substation	150	150	12/31/2005	Application accepted
GI-2004-2	2/9/2004	Wind	Network +Energy Resource	Baca Co., CO	Lamar Substation	238	238	9/31/2005	Application accepted

Table 2 - PSCO RMAO Generator Interconnection Queue

Once generation sites were agreed upon, three different generation scenarios were created based on regional groupings:

- Scenario One placed the majority of the generating resources in southern Colorado to evaluate how transmission would have to be built into the Front Range from the south.
- Scenario Two placed the majority of new generating resources in northern Colorado to evaluate how transmission would have to be built to the Front Range from the north.
- Scenario Three was meant to demonstrate a balanced distribution of the generation between the northern and southern areas of Colorado to evaluate how transmission would have to be built into the Front Range from both regions.

At the time this study was initiated, PSCo had not yet determined the location of its proposed 750 MW generator. Therefore, Scenario One modeled the coal plant at the Comanche Station and Scenario Two modeled the coal plant at the Pawnee Station. This would ensure that generation and transmission would be studied regardless of which facility PSCo chose. Scenario Three was created to evaluate a more balanced distribution of generation in eastern Colorado.

Maps of the three generation scenarios that show the approximate locations of the additional generation resources, can be found in Appendix D.

Table 3 describes the placement of the new 2750 MW of resources for each of the three scenarios.

	SCENARIO 1	SCENARIO 2	SCENARIO 3
Generation Site	**Modified 1/28/04**	**Modified 1/28/04**	**Modified 1/28/04**
Comanche	750	0	750
Southeast Coal (Boone)	550	0	500
Midway	200	200	150
Lamar (Sand Sage)	230	0	0
Nixon	200	100	0
Corner Point	500	500	0
Pawnee	0	750	500
Brush (Pawnee)	0	300	150
Plains End	0	100	0
Blue Spruce	0	500	250
St.Vrain	0	100	0
Northern Weld (Weld)	100	0	100
Big Sandy / Lincoln	0	200	250
Burlington	220	0	100
Total	**2750**	**2750**	**2750**

Table 3 - Generation Scenarios

C. Brainstorming of Transmission Topology

Once the three generation scenarios were developed, the group created a preliminary list of transmission additions that would be examined to accommodate the added generation for each scenario. In addition to the system knowledge and expertise of the planners, the following basic planning philosophies were used as the transmission solutions were developed:

- Develop transmission that could accommodate a variety of generation placement (or options),
- Consider the needs and interests for Colorado load-serving entities by conducting joint planning,
- Manage issues associated with parallel low voltage networks,
- Maximize use of existing transmission corridors where prudent,
- Establish new transmission corridors,
- Establish 345kV voltage in the Front Range,

- Pre-construct for higher voltage operation,
- Pre-construct for future circuits,
- Acquire additional rights-of-way when possible for future transmission,
- Build new transmission adjacent to existing substations to allow for future sectionalizing.

The preliminary transmission solutions developed for regional issues are not meant to imply any specific plans or commitments by participating entities, but are meant to gain an understanding of the relative magnitude in terms of quantity and cost of the localized load-serving solutions that might ultimately be implemented should the forecast load growth occur.

Table 4 shows the initial bulk transmission that was to be added to the three scenario cases.

Potential Transmission Infrastructure			
Scenario	**Description**	**Entity**	**Element**
1	S.Gens	PSCo	Comanche – Daniels Park 345kV X2
1	S. Gens	PSCo	Comanche - Boone 345kV X2
1	S. Gens	PSCo	Boone - Corner Point (via B.Sandy) 345kV X2
1	S. Gens	PSCo	345/230kV autos at Boone, Corner Pt., Spruce, Daniels, Green Valley, Comanche
1	S. Gens	TSGT	SECoal - Boone 230 / 345kV
1	S. Gens	TSGT	SECoal - Lamar 230kV
1	S. Gens	PSCo	Big Sandy - Corner Point 345kV
1	S. Gens	TSGT	SECoal – Walsenburg 230 / 345kV
1	S. Gens	WAPA	Burlington - Wray 230kV
1	S. Gens	PSCo	Corner - Smoky / Daniels 345kV
1	S. Gens	PSCo	DC Tie expansion 230MW
1	S. Gens	PSCo	Boone - Lamar 230kV rebuild to Double-ckt 230kV
1	S. Gens	PSCo	Blue Spruce - Green Valley 345kV upgrade double-ckt
1	S. Gens	PSCo	Blue Spruce - Smoky Hill 345kV
1	S. Gens	PSCo	Blue Spruce - Daniels Park 345kV
1	S. Gens	CSU	Kelker - Drake upgrade from 115kV to 230kV
1	S. Gens	CSU	230/115kV auto at Drake
2	N. Gens	PSCo	Pawnee - Ft.Lupton double-ckt 230kV
2	N. Gens	PSCo	Pawnee - Corner Point 345kV X2
2	N. Gens	PSCo	Corner Point - Daniels Park 345kV X2
2	N. Gens	PSCo	Corner Point - Smoky Hill230kV X2
2	N. Gens	PSCo	Blue Spruce - Smoky Hill 345kV
2	N. Gens	PSCo	345/230kV autos at Pawnee(2), Corner Point(2), Daniels Park(3),
2	N. Gens	WAPA	Beaver Creek - Brush Upgrade
2	N. Gens	WAPA	Beaver Creek - Hoyt 230kV
2	N. Gens	WAPA	Beaver Creek 230/115kV two new parallel transformers
2	N. Gens	PSCo	St.Vrain - Niwot - Lookout sectionalize at Plains End
2	N. Gens	PSCo	Big Sandy - Corner Point 230 / 345kV
2	N. Gens	CSU	Kelker - Drake upgrade from 115kV to 230kV
2	N. Gens	CSU	230/115kV auto at Drake
2	N. Gens	WAPA	Poncha – east
3	Balanced	PSCo	Comanche – Daniels Park 345kV X2
3	Balanced	PSCo	Comanche - Boone 345kV X2
3	Balanced	PSCo	Boone - Big Sandy 345kV X2
3	Balanced	PSCo	Big Sandy - Corner Point 345kV X2
3	Balanced	PSCo	345/230kV autos at Corner Point, Daniels Park, Comanche, Pawnee
3	Balanced	CSU	Kelker - Drake upgrade from 115kV to 230kV
3	Balanced	CSU	230/115kV auto at Drake
3	Balanced	PSCo	Pawnee - Ft.Lupton double-ckt 230kV
3	Balanced	PSCo	Pawnee - Corner Point 345kV X2
3	Balanced	PSCo	Corner Point - Daniels Park 345kV X2
3	Balanced	PSCo	Corner Point - Smoky Hill 230kV X2
3	Balanced	PSCo	Blue Spruce - Smoky Hill 345kV
3	Balanced	TSGT	SECoal - Boone 230 / 345kV
3	Balanced	TSGT	SECoal - Lamar 230kV
3	Balanced	TSGT	SECoal – Walsenburg 230 / 345kV

Table 4 – Initial Bulk Transmission

D. Base Case Development

1. Source Case

Studies were initiated using the WECC 2014HS base case, which is the ten-year planning case developed for the 2004 Study Program. At the time of this writing, the case was not officially released by WECC due to final comments from other entities in WECC. However, the case was extensively reviewed and additional comments provided by the study participants. Significant elements of the case modeling are listed below.

a.) The PSCo forecast used for these cases was a June 2003 Peak Demand Forecast at a 90% probability factor (7991 MW Native Load w/DSM).

b.) To create the 11-13% planning reserves, power was imported from outside the Colorado power flow area. Interchange from the WAPA Colorado/Missouri (WACM) control area to the PSCo control area was kept at around 800 MW.

c.) Transmission elements developed by the participants were implemented into the appropriate study models. Some minor modeling changes were also implemented into the cases.

2. Load & Other Base Case Modifications

a.) PSCO

PSCo's forecasting method is based on a peak demand value that is produced by the Xcel Energy Forecasting Group. This peak demand value is based on weather, economics & resale probability factors. The peak demand value is then broken down into wholesale demands, losses & power purchase capacity contracts in order to allocate a demand value to PSCo only facilities. PSCo’s portion of the total Native Load demand is then allocated to PSCo load buses based on historical peak demands and future substation additions.

b.) CSU

The CSU summer peak demand forecasting methodology integrates weather, monthly electric sales and other variables. The forecasts are estimated for historical demands that occurred when the temperature was over 91 degrees on non-holiday weekends from 1992-2003. The weather variables in the summer peak demand equations include maximum temperature, sum of cooling degree-days for the peak day and the preceding two days. The first set captures the impact of peak temperature while the second set captures the heat build-up over several days. CSU monthly sales variables were used to explain the growth in peak and energy in the historical data and to translate the sales forecast into peak demand.

c.) TSGT

Tri-State's load forecast is consistent with the 2002 Load Forecast required biannually by the Rural Utilities Service (RUS), Department of Agriculture. The forecast was included in the 2003 Tri-State Electric Least-Cost Resource Plan submitted to the Colorado Public Utilities Commission in October 2003. The severe weather scenario of the 2002 load forecast was selected since there can be significant load variations caused by weather. Because the study area includes only a portion of Tri-State's service area, the sum of individual member demands was used. The result is a severe weather, member summer peak load forecast of 1879 MW for 2014.

d.) Aquila

Aquila Networks used their latest peak demand forecast for this study. As previously stated, Aquila loads are not shown as PSCo's responsibility for 2014 in the L&R sheet, as the current supply contract expires in 2011. Aquila loads were modeled as served from excess generation within the PSCo system.

e.) PRPA

PRPA used their October 2003 Official Ten-Year Monthly Loads & Resources Forecast to allocate loads to their respective buses based on historical peak demands and future substation additions. Platte River's summer peak for native load (and losses) is projected to increase 45% from 571 MW in 2003 to 825 MW in 2014.

3. Generation

The generation dispatch of Colorado generating units was modeled by the WECC Rocky Mountain Region Area Coordinator. Incremental fuel costs are applied when modeling the PSCo units as well as coordinating a 13% operating reserve margin. The powerflow models show power imported from the Northwest, U.S. or Northern California to eliminate the need for fictitious generation to balance the load. This made it easier to dispatch the new scenario generation to match the respective scenario requirements.

The CLRTPG participants each have different operating and planning reserve requirements. PSCo's unit dispatch, including Aquila owned units, for the generation scenario cases were configured to create a planning reserve margin near 13%. The 13% reserve margin is a value that Xcel Energy's Resource

Planning Group applies when determining resource requirements.[5] This is a planning reserve margin that was placed in the scenario cases to meet the resource needs from Table 1.

Tri-State's reserve margin is developed for operating purposes consistent with the Rocky Mountain Reserve Group (RMRG). For long-range planning studies, Tri-State has determined that the combination of operating reserve requirements and forecasting based on a severe weather scenario results in an overall long-range planning reserve margin that is both adequate for reliability and economical for Tri-State's member systems.

PRPA, WAPA and CSU used approximations from the Rocky Mountain Reserve Group that has participant operating reserve requirements for the loss of the largest generator in the region.

All the reserve requirement values were factored into the resource needs for the Front Range and can be seen in the Loads & Resources documents in Appendix B.

Models of existing generators of similar size were used as a basis to represent the new scenario generators. For example, the Pawnee and Comanche 750 MW coal units were modeled using a Four Corners 750 MW coal unit. Most of the scenario generation was not fuel-type specific since the intent of the study was to focus on long-term transfer of power to the demand.

IV. Preliminary Analysis

The primary method for system analysis was evaluation of single contingency (N-1) performance using traditional power flow software tools. No stability analyses were carried out for this phase of studies. The evaluation concentrated on observing contingency loading and attempting to maintain element loadings to within stated normal rated values. System voltages were also observed, but not emphasized since the Group agreed that voltage issues would ultimately be managed by LSE's regular planning studies and would not affect the development of backbone transmission.

A. Backbone vs. Regional Issues

Preliminary analysis of the backbone transmission additions revealed regional deficiencies that were due to local load growth as well as those due to the implementation of new generation. In most cases, those issues existed for all scenarios studied. To evaluate only the high-voltage requirements for the additional generation resources, the regional issues had to be alleviated. In some instances, entities have already evaluated and identified remedies for expected concerns on their systems. However, the models representing the system ten

[5] Based on information obtained from Xcel Energy Resource Planning Group in January of 2004. Xcel Resource Planning Group has since determined that it requires a 17% reserve margin.

years into the future revealed other problems that had not been previously identified. Therefore, a great deal of effort was taken to develop potential solutions for those issues.

The transmission solutions developed for regional issues are not necessarily specific plans or commitments by associated entities, but are meant to gain an understanding of the relative magnitude in terms of quantity and cost of the localized load-serving solutions that might ultimately be implemented should the forecasted load growth occur.

B. Plan Verification

Sensitivity analyses were performed on the scenarios to determine the adequacy of the initially proposed transmission components and to evaluate alternatives to the proposed transmission. Single contingency (N-1) analyses were run on the cases to identify remaining facility overloading or voltage issues. Most of the participating LSE's had previously identified regional issues on their facilities and provided modeling updates and fixes to remedy the contingency violations. The scenario cases were revised to reflect the modifications and changes. These steps were repeated until the scenario cases showed no major load serving or power transfer issues in the Front Range.

C. Transmission Costs

The overall transmission investment estimates in this report represent a combination of budgeted and unbudgeted projects. Projects that have been contemplated through a study participant's normal budgeting process were included in the CLRTPG overall investment estimate as budgeted by the participant. However, additional projects for which a detailed cost estimate had not been prepared were estimated utilizing generic unit costs. The intent was to gain insight into the magnitude of transmission investment that could be expected in the ten-year timeframe to support the anticipated level of generation expansion. The generic costs were used as a proxy for detailed estimates.

The origin for most of the generic unit costs was the Southeast Coal Study from 2002. This set of generic cost estimates was escalated by an annual inflation rate of 2.5%, to represent 2004 dollars. The list was also expanded to include some facilities that were not a part of the original Southeast Coal Study. The list of generic cost estimates can be found in Appendix F.

V. Results

The overall approximate transmission costs for the three scenarios are shown in Table 5. All cost approximations are shown in millions of present year (2004) dollars.

PSCo had the largest transmission costs for all scenarios which correlates to PSCo's having the greatest resource need.

Entity	Scenario 1 - 2750MW	Scenario 2 - 2750MW	Scenario 3 - 2750MW
Aquila	$37.9	$25.6	$37.9
CSU	$41.1	$23.4	$41.1
PRPA	$60.0	$60.0	$60.0
PSCo	$443.8	$227.6	$477.2
TSGT	$138.2	$75.3	$138.2
Western	$66.0	$103.3	$102.1
Total	**$786.9**	**$515.1**	**$856.5**

Table 5 - Scenario Transmission Costs[6] (Millions - 2004 dollars)

The transmission that was added to each scenario was directly influenced by the specific generation additions and dispatch. For example, Scenario One, which models the majority of the new generation in the southern part of the system, consequently had reduced generation levels in the northern area. This resulted in facilities staying within N-1 criteria limits in the northern area that might otherwise be expected to exceed limits for other dispatch patterns. The same can be said about the north scenario case, Scenario Two, for which generation in the southern part of the system was reduced. This should be taken into consideration when reviewing the costs shown for each scenario. Since it is likely that future generation resources will develop throughout the Front Range, rather than be concentrated in the north or south, the costs for Scenario Three may be more reflective of the actual long-term costs.

The "bulk" transmission as defined in this report includes all facilities with an operating voltage of 230kV and above, including 230-115kV autotransformers. The "Primary Bulk" transmission describes the essential high-voltage components of the back-bone alternatives. Detailed Bulk and Regional transmission costs and results will be explained in the next three sections.

A. Scenario One

1. Bulk Transmission Description

Scenario One modeled the majority of new generation in the southern portion of the Front Range of Colorado. The primary bulk transmission required is shown in Table 6.

The primary bulk transmission for Scenario One consists of 345kV transmission between the Comanche and Daniels Park substations, and between the Comanche and Corner Point substations. The Corner Point substation would be a new major substation, which would sectionalize the existing Pawnee - Daniels

[6] Preliminary analysis indicated that an additional $15 million could be required for approximately 300 MVARs of reactive support to mitigate voltage issues. This would be true for all scenarios.

Park and Pawnee - Smoky Hill 230kV lines near the town of Deer Trail, Colorado. It would include 345-230kV autotransformation, and 230kV and 345kV line terminations, facilities, and equipment. With added generation at Comanche, SE Coal and Lamar, two separate high-voltage 345kV corridors were chosen to accommodate the majority of the necessary transmission.

Description	Entity	Miles	Cost 2004 dollars
Comanche-Boone-Corner Point 345kV (1) Double Tower OCS	psco	181	$102,900,000
Corner Point - Smoky Hill 230 kV Rebuild	psco	40	$25,526,000
Corner Point - Daniels Park 230kV line #2 (Sect. @ Smoky Hill)	psco	64	$18,000,000
Comanche-Daniels Park 345kV Project (includes Autos at Comanche (2) and Daniels Park (3), and Line Terminations)	psco	125	$134,209,000
Boone Substations (includes 2 Autos & Line Terminations)	psco	0	$21,096,000
Corner Point Substations (includes 2 Autos & Line Terminations)	psco	0	$22,501,000
Lamar HVDC Expansion (230 MW)	psco	0	$35,050,000
Lamar - Boone 345kV Double ckt Operated @ 230kV	psco	98	$54,230,000
SECoal - Boone 230kV	tri-state	52	$15,600,000
SEC - Walsenburg 230kV	tri-state	147	$44,100,000
Total		**708**	**$473,212,000**

Table 6 - Scenario One Primary Bulk Transmission

The new Comanche generation was modeled with generation step-up transformation to 345kV high-side voltage. The Comanche substation would be expanded to accommodate two 345-230kV autotransformers, 230kV line terminations and 345kV facilities. The transmission between Comanche and Daniels Park substations would consist of double-circuit 345kV transmission, with a majority of the transmission utilizing existing transmission corridors. The transmission between Comanche and Corner Point would consist of a single 345kV circuit on double-circuit capable towers establishing a new transmission corridor. Initial analysis of the Comanche – Corner Point transmission evaluated two 345kV lines strung single-circuit on two double-circuit towers. As load and generation developed, the transmission circuits could be built out to full double-circuit capability at 345kV if required and could be sectionalized as necessary at the Big Sandy substation. The Comanche-Corner Point 345kV transmission would be sectionalized at Boone with two 345-230kV autotransformers. The SE Coal plant was modeled south of LaJunta with 230kV transmission lines to Boone, Walsenburg, and Lamar. An additional 230 MW was placed at Lamar to model an expansion of the 210 MW HVDC Tie. Two Lamar to Boone 345kV transmission circuits, operated at 230kV would be placed on a double circuit tower to accommodate the added tie capacity.

Studies showed that an additional 230kV line from Corner Point to Daniels Park would be needed. This new 230kV line would be sectionalized at the Smoky Hill substation to relieve injection into the Daniels Park substation. The new 230kV line would be built for 345kV transmission but operated at 230kV. Presently, there are two existing 230kV transmission lines from the Pawnee substation to the Daniels Park substation. One of these 230kV lines is sectionalized at the Smoky Hill substation. Both 230kV lines are on single circuit towers from Pawnee to just outside the Smoky Hill substation. From there, the two 230kV lines are on common towers and terminate at Daniels Park. One of the study goals was to utilize existing right-of-way corridors for rebuilding or adding new transmission in efforts to both minimize environmental impacts as well as cost. The transmission addition between Corner Point and Daniels Park is consistent with this goal.

A map of the primary bulk transmission for Scenario One can be found in Appendix D.

An additional $73.9 million in other bulk costs was required for the Scenario One model. These included costs of a San Luis to Walsenburg 230kV line, adding a second RD Nixon to Kelker 230kV line, adding a new Story to Hoyt 230kV line and installing a second Lamar 230-115kV autotransformer. A detailed list of all other bulk costs for Scenario One can be found in Appendix C in the Transmission Infrastructure Spreadsheet. The third column designates a "B" for Bulk transmission and an "R" for Regional transmission. The columns labeled "S1", "S2", and "S3", refer to Scenarios 1, 2, and 3. The "X" in these columns show the facilities required for each Scenario.

A total of $239.8 million in regional transmission was added to Scenario One to accommodate the added loads and generation resources. This includes upgrading approximately 514 miles of transmission lines throughout the Front Range. All PRPA upgraded/added facilities are included into these regional miles and cost estimates. A detailed list of all regional changes for Scenario One can be found in Appendix C in the Transmission Infrastructure Sheet.

Maps of the Front Range underlying systems can be found in Appendix E to show the existing facility and line configurations.

2. Study Results

The various sensitivities for Scenario One were analyzed using single contingency analysis and comparing the results to the benchmarking case and/or other similar sensitivities. The following shows the results of the sensitivity studies that were performed. Bulk lines and facilities that were found to be unnecessary were not included in the overall costs for Scenario One.

Analysis of Scenario One consisted of refining the power flow models to develop a system that is reliable but not over-built. Special attention was given to Scenario One since during the course of studies, on February 17th, 2004, PSCo announced plans to pursue a 750 MW unit at the Comanche generating station (Comanche Unit #3). Studies concentrated on verifying that the amount of transmission initially placed in the model was appropriate. Sensitivity analyses were performed to determine if any viable alternatives existed.

The initially proposed transmission path from the South Front Range to the North was to follow a Comanche to Boone to Corner Point eastern transmission corridor. The transmission from Boone to Corner Point was proposed as an expandable route that would have two double circuit 345kV capable towers, initially having only one circuit strung. This would allow for future expansion of transmission from Boone to Corner Point. However, studies showed that an adequate transmission solution would be to develop a single eastern double-circuit 345kV line from Boone to Corner Point combined with a double-circuit 345kV transmission from Comanche to Daniels Park utilizing the existing western corridor. This transmission arrangement would be adequate for the Scenario One generation.

Once PSCo had announced plans to pursue the Comanche Unit #3 generation, it intensified the evaluation of transmission alternatives to specifically accommodate that generation utilizing a 2010 system model. Those studies took place concurrently with this study. Those studies also revealed several advantages to developing transmission in or near the existing western corridor. Of the alternatives studied, the one that showed the best results consisted of 345kV transmission that would utilize the existing corridor between Comanche, Midway, and Daniels Park substations. Preliminary cost estimates also showed that initial development of a Comanche – Daniels Park transmission project would have economic benefits as well. The Comanche Unit #3 studies indicated that the cost to build an eastern alternative to accommodate the proposed 750MW of new generation would be up to twice as much as initially building a western alternative transmission project.

Subsequent long-range studies evaluated a transmission approach that considered the Comanche-Midway-Daniels Park double-circuit 345kV Project and a single circuit Comanche-Boone-Corner Point 345kV transmission line as part of the overall 2014 system. The results for this Scenario One analysis indicated that this level of transmission was adequate and consistent with an overall long-range back-bone transmission system. In addition, the cost estimates indicated the total costs for this Scenario were reduced by approximately $43.3 million following this approach compared to an entirely eastern double-circuit 345kV transmission development.

The western alternative transmission associated with Comanche Unit #3 generation project establishes the first phase of a long-range transmission plan that includes an increased level of southern generation. When conditions warrant, transmission expansion to the east may be developed to establish additional phases of the long-range plan.

The Green Valley to Smoky Hill 230kV line and the 3rd Spruce to Smoky Hill line were not necessary for the Scenario One model. Both lines did not load to the expected levels and the system exhibited adequate performance without these lines.

Preliminary development included a SE Coal to Lamar 230kV line. Studies showed with the addition of double circuit Boone to Lamar 345kV lines operated at 230kV that the SE Coal to Lamar 230kV line was not necessary. Since Lamar and SE Coal buses were acting as sources, the line flow between Lamar and SE Coal was minimal and would not have any significant benefits compared to the cost of building such a line. Therefore the SE Coal to Lamar 230kV line was removed from subsequent Scenario One studies.

Preliminary development included two 345-230kV autotransformers to help accommodate the additional Lincoln generation. Studies showed that these autotransformers did not have an impact in the reliability of the regional system and therefore were removed from subsequent Scenario One studies.

The SE Coal to Corner Point 230kV line and Lamar to Corner point 230kV line were studied in addition to the Boone – Corner Point 345kV transmission. These lines were modeled as tied together at a tap point along the Boone – Corner Point 345kV line, with a 230/345kV transformer at this point. Results indicated that these 230kV lines were not carrying the amounts of power expected. Sensitivity studies were performed at 345kV with similar results. Results indicate some level of mitigation was needed for some overload issues, particularly in the Colorado Springs area. Further analysis is needed to justify the cost benefit.

The addition of a 2nd Comanche to Reader 115kV line helped to alleviate the 115kV single contingency problems between Airport Memorial to Reader and Boone to Airport Memorial. This line addition has value for the Southern Front Range in that it provides reliability for the underlying 115kV and 69kV systems.

Sensitivity studies looked at finding ways to distribute the injection into the Denver metro area and relieve the contingency overloads between Daniels Park and Greenwood substations. Injections into the Daniels Park bus caused significant power flows on the two Daniels Park to Greenwood 230kV transmission lines. Loss of either 230kV line would load the other line above its thermal rating. To alleviate this problem, the Tarryall to Daniels Park 230kV line was sectionalized at Waterton and the Corner Point to Daniels Park 230kV line was sectionalized at Smoky Hill. This alleviated the injection problems into Daniels Park and directed flow through Smoky Hill.

B. Scenario Two

1. Bulk Transmission Description

Scenario Two modeled the majority of new generation in the Northern Front Range of Colorado. The primary bulk transmission required is shown in Table 7.

The primary bulk transmission consisted of transmission from the Pawnee substation to the Corner Point substation and on to the Daniels Park substation. The existing Pawnee to Ft. Lupton 230kV line would be upgraded to a double circuit 345kV line operated at 230kV. The existing 230KV lines from Pawnee to Smoky Hill and Daniels Park substations would be rebuilt to two 345kV lines from Pawnee to Corner Point substation. The existing 230kV transmission between Corner Point and Smoky Hill would be rebuilt to double circuit 230 kV. The existing 230kV transmission from Corner Point to Daniels Park would be rebuilt to double circuit 345kV transmission with both circuits sectionalized at the Smoky Hill substation. The Pawnee, Smoky Hill and Daniels Park substations would be expanded for 345kV facilities and equipment. A new 230kV line from Big Sandy to Story would be built to accommodate the added generation near Lincoln or Big Sandy. A map of the primary bulk transmission for Scenario Two can be found in Appendix D.

Description	Entity	Miles	Costs 2004 dollars
Corner Point - Smoky Hill 230 kV Rebuild	psco	40	$25,526,000
Corner Point - Smoky Hill 345kV Double ckt	psco	40	$30,559,000
Smoky Hill - Daniels Park 345kV Double ckt	psco	24	$21,271,000
Pawnee - Corner Point 345kV Double ckt	psco	55	$24,720,000
Corner Point Substations (includes 2 Autos & Line Terminations)	psco	0	$22,501,000
Daniels Park Substation (includes 3 Autos & Line Terminations)	psco	0	$20,927,000
Pawnee Substation (includes 2 Autos & Line Terminations)	psco	0	$11,500,000
Pawnee - Ft.Lupton double-ckt 230kV	psco	64	$42,850,000
Big Sandy - Story 230kV New Line	wapa	67	$21,181,000
Total		**290**	**$221,035,000**

Table 7 - Scenario Two Bulk Transmission

An alternative to the Big Sandy to Story 230 kV line is a Big Sandy to Beaver Creek 230 kV line. This sensitivity was not modeled in the Colorado Long Range Transmission Planning studies but will be included in future studies. This change is due to the several 230 kV transmission lines projected to terminate at Beaver Creek in the future. A Big Sandy to Beaver Creek 230 kV transmission line would be approximately the same length and use the same right of way as the Big Sandy to Story 230 kV line. Costs estimates for addition of a 230 kV Beaver Creek substation are not reflected in the transmission infrastructure spreadsheet. The Beaver Creek 230 kV substation would add approximately $6 million dollars to WAPA’s cost estimates for Scenario Two and Three.

An additional $70.9 million in other bulk costs were added to the Scenario Two model. For instance, this included installing a second Chambers 230-115kV autotransformer, constructing a new Kiowa Creek to Story 230kV line, adding a new Story to Hoyt 230kV line, and installing a second Weld 230-115kV autotransformer. A detailed list of all other bulk costs for Scenario Two can be found in Appendix C in the Transmission Infrastructure Sheet.

A total of $223.1 million in regional transmission was added to Scenario Two to accommodate the added loads and generation resources. This includes upgrading approximately 492 miles of transmission lines in the Front Range. All PRPA upgraded/added facilities are included into these regional miles and cost estimates. A detailed list of all regional changes for Scenario Two can be found in Appendix C in the Transmission Infrastructure Sheet. Maps of the Front Range underlying systems can be found in Appendix E to show the existing facility and line configurations.

2. Study Results

Some sensitivity studies for Scenario Two evaluated the effects that a high concentration of generation in northern Colorado would have on the TOT 3 transfer path. The path owners wanted to ensure that import capability of the path would not be impacted with the addition of generation in the northeastern part of the system. The sensitivity analysis indicated that the Scenario Two generation pattern did not adversely affect the TOT 3 limit.

Some sensitivity studies modeled additional 230kV transmission from Miracle Mile to the Ault substation. Preliminary results showed that the added transmission increased the TOT 3 rating. Further sensitivity analysis must be done to verify and fully analyze the addition of lines to increase the TOT 3 limit.

The addition of generation at Lincoln required new 230kV transmission. A Big Sandy to Story 230kV line was modeled and showed that this new transmission would be beneficial. Future studies of similar content will be done to evaluate added transmission near the Lincoln and Big Sandy areas.

Preliminary models showed a third Smoky Hill to Spruce 230kV line and a Green Valley to Smoky Hill 230kV line. Sensitivity analysis showed that both of these 230kV lines were not needed for this Scenario.

The proposed 345kV transmission between Pawnee and Daniels Park for this Scenario was studied to verify if the 345kV lines were over-built. Various scenarios with a single 345kV line from Pawnee to Corner Point were evaluated and analyzed mainly to determine if transmission costs could be reduced in any way to accommodate the generation. Sensitivity analysis and contingency results indicated that the two single circuit 345kV lines from Pawnee to Corner Point were necessary for the Scenario Two generation. Other regional problems showed up for the sensitivity studies that did not exist with the original two 345kV lines from Pawnee to Corner Point. Adding a third Pawnee to Ft. Lupton 230kV line instead of a second 345kV line from Pawnee to Corner Point was studied. Single contingency results showed line overloading on the Ft. Lupton to Henry Lake 230kV line and the Smoky Hill to Meadow Hills 230kV line. A Pawnee to Green Valley alternative was studied, but contingency results showed line overloading between Smoky Hill and Spruce and again from Smoky Hill to Meadow Hills. All options that removed the second 345kV line from Pawnee to Corner Point resulted in a Smoky Hill to Meadow Hills 230kV overloading for single contingency. Further cost analysis will need to be done in order to compare the second 345kV line from Pawnee to Corner Point with the required Smoky Hill to Meadow Hills upgrades/fixes.

Overall, the required transmission that was modeled for this case was adequate to support the generation and 2014 load forecast demands for this scenario. The total approximate cost of $515 million dollars should provide the required transmission for the Scenario Two generation.

C. Scenario Three

1. Bulk Transmission Description

Scenario Three modeled a balanced generation pattern in the Front Range of Colorado. The primary bulk transmission required is shown in Table 8.

Description	Entity	Miles	Costs 2004 dollars
Comanche-Boone-Corner Point 345kV (1) Double Tower OCS	psco	181	$102,900,000
Corner Point - Smoky Hill 230 kV Rebuild	psco	40	$25,526,000
Corner Point - Smoky Hill 345kV Double ckt	psco	40	$30,559,000
Smoky Hill - Daniels Park 345kV Double ckt (includes 345kV Line Terminations)	psco	24	$21,271,000
Pawnee - Corner Pt 345kV Double ckt	psco	55	$24,720,000
Blue Spruce - Smoky Hill 345kV	psco	11	$5,778,432
(1) 345-230kV auto at Spruce	psco	0	$5,253,125
Comanche-Daniels Park 345kV Project (includes Autos at Comanche (2) and Daniels Park (3), and Line Terminations)	psco	125	$134,209,000
Boone Substations (includes 2 Autos & Line Terminations)	psco	0	$21,096,000
Corner Point Substations (includes 2 Autos & Line Terminations)	psco	0	$22,501,000
Pawnee Substation (includes 2 Autos & Line Terminations)	psco	0	$11,500,000
Pawnee - Ft.Lupton double-ckt 230kV	psco	64	$42,850,000
SECoal - Boone 230kV	tri-state	52	$15,600,000
SEC - Walsenburg 230kV	tri-state	147	$44,100,000
Big Sandy - Story 230kV New Line	wapa	67	$21,181,000
Totals		**806**	**$529,044,557**

Table 8 - Scenario Three Bulk Transmission

The infrastructure placed in the Scenario Three model was derived from data used for Scenarios One and Two. The primary southern transmission consisted of the 345kV transmission between the Comanche and Daniels Park substations, and between the Comanche and Corner Point substations. The primary northern transmission consisted of 345kV transmission between Pawnee, Corner Point, and Daniels Park substations.

The development from Corner Point into Denver would require additional modification due to the increase in power injection from both the north and the south. The Corner Point substation would have to accommodate two 345-230kV autotransformers, 230kV line terminations and 345kV facilities and equipment. From Corner Point, the two 230kV circuits to Smoky Hill and Daniels Park substations would be upgraded. The final configuration would consist of two 345kV circuits from Corner Point to Daniels Park and two 230kV circuits from Corner Point to Smoky Hill to Daniels Park. The Daniels Park substation would require 345/230kV autotransformers and additional 230kV terminations. A map of the primary bulk transmission for Scenario Three can be found in Appendix D

An additional $86.3 million in other bulk costs was added to the Scenario Three model. For example, this included an upgrade of the Englewood to Arapahoe 115kV line to 230kV, adding a third Comanche 230-115kV autotransformer, constructing a second Rawhide to Laporte 230kV line and upgrading the Kelker to Drake 115kV line to 230kV. A detailed list of all other bulk costs for Scenario Three can be found in Appendix C in the Transmission Infrastructure Sheet.

A total of $241.2 million in regional transmission was added to Scenario Three to accommodate the added generation. This includes upgrading approximately 521 miles of transmission lines throughout the Front Range. All PRPA upgraded/added facilities are included into these regional miles and cost estimates. A detailed list of all regional changes for Scenario Three can be found in Appendix C in the Transmission Infrastructure Sheet. Maps of the Front Range underlying systems can be found in Appendix E to show the existing facility and line configurations.

2. Study Results

The sensitivities evaluated for this scenario consisted of looking at ways to reduce flows on the load serving transmission lines within the Denver Metro Region. One method evaluated included sectionalizing the PSCo Tarryall to Daniels Park 230 kV line at Waterton. Other sensitivities focused on ways to unload the 115 kV and 230 kV transmission lines leaving the Smoky Hill Substation to the West. This included tying in the Buckley 230 kV buses and converting 115 kV lines to 230 kV from Smoky Hill to East Substation. Additional studies will be required to determine the most efficient means to provide loading relief to the Denver metro transmission system. Study efforts to identify solutions to unload the areas south of Denver such as Colorado Springs and Pueblo should be pursued by those LSE’s.

Since future generation is likely to be added to both northern and southern Front Range regions, Scenario Three may be a better description of what to expect in the upcoming years. This also implies that the Scenario Three transmission costs may be more characteristic of the future investment needed for the entire Front Range of Colorado.

VI. Final Conclusions

A. Results of Scenario One indicate that building double-circuit 345kV transmission from Comanche to Daniels Park, and single-circuit (double-circuit capable) 345kV transmission from Comanche to Boone to Corner Point would provide adequate primary transmission for the long-range southern generation scenario. Initial development of the Comanche – Daniels Park transmission (to accommodate the Comanche Unit #3) is consistent with, and will establish the first phase of, the overall long-range transmission plan. As load and generation develop in the Front Range, additional transmission in an eastern corridor should be pursued.

B. The results of the Scenario Two analyses indicated that building 345kV transmission between Pawnee, Corner Point, Smoky Hill, and Daniels Park would provide the primary transmission necessary to accommodate northern generation development. Although the costs for the Scenario Two transmission were less than Scenarios One or Three, study results indicate little transmission capacity margin exists with this transmission. Future studies will evaluate the overall injection capability established with the Scenario Two transmission. It appears that Scenario One transmission, although more costly, results in greater transmission capacity margin.

C. Preliminary analysis of Scenario Three identified some potential transmission modifications that could alleviate power flow loading on the lines in southern Denver-metro area. Since it is likely that future generation resources will develop throughout the Front Range, rather than concentrated in the north or south, the costs for Scenario Three may be more reflective of the actual long-term costs. Additional analysis should be continued for the Scenario Three.

D. The Corner Point to Smoky Hill and Daniels Park corridor requires expansion in all three scenarios. Scenario One only required an additional 230kV line between Corner Point and Daniels Park. For the other two scenarios, double-circuit 345kV transmission was required in that corridor.

F. For future studies, the CLRTPG may need to follow up with additional investigations, including an evaluation of the TOTs and additional studies of the balanced generation scenario. The CLRTPG will continue on the path of studying the future of the transmission system with the results from this study as a foundation of that work. The Group plans to jointly review PSCo's Least Cost Planning efforts, including the transmission studies that will take place as part of the bid analysis for PSCo resource needs beyond the Comanche Unit

#3. Due to anticipated load growth in Colorado over the next 10 years, implementation of new generation in the Front Range will continue. The results of this study provide the LSE's in the state with insight to the effects of added generation at various locations and what transmission might be necessary.

APPENDIX A

Invitation to Provide Input and Assist With Regional 10-Year Transmission Plan

12/19/03

To: Transmission Planners of the Colorado Coordinated Planning Group

Re: Invitation to Provide Input and Assist With Regional 10-Year Transmission Plan

Public Service Company of Colorado (PSCo) anticipates the need to add transmission in the next ten years in order to support new generation resources and serve loads. In order to help assure that those transmission additions complement all the needs of utilities and load serving entities in our region, we propose to form a Long-Range Transmission Subcommittee to the CCPG, and would welcome the opportunity to secure the input of your transmission planning staff. To secure that input, we are hosting a half-day meeting January 9, 2004, at 9:30 AM, to be held at the offices of Tri-State Generation and Transmission Association (1100 West 116th Street, Denver). I hope that your transmission planning experts can attend.

Agenda:

- Colorado load-serving entities verify / provide their 10-year (through 2014) customer load forecasts to refresh the transmission planning model

- Input regarding size, timing and general location of the most likely generation resource additions to serve Colorado customers

- Identify organizations that are willing and able to contribute transmission planning assistance.

PSCo plans to develop a high-level, 10-year transmission plan that supports Colorado's load growth for filing with the Colorado Public Service Commission in April of 2004. We welcome your organization's input and any assistance you can give in helping to develop a plan that efficiently addresses all our customers' needs.

If you have any questions about the agenda for the meeting, I encourage you to contact PSCo's Manager of Transmission Planning, Sandra Johnson (303-571-7095).

APPENDIX B

Loads and Resources Balance Sheets

APPENDIX C

Transmission Infrastructure Data Sheets

APPENDIX D

Scenario Generation and Primary Bulk Transmission Maps

APPENDIX E

Front Range Regional System Maps

APPENDIX F

TSGT Cost Estimation Guide