Appendix O

Tri-State Generation and Transmission Association, Inc.

Supporting Documents

Tri-State's Appendix O

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COLORADO COORDINATED PLANNING GROUP

SAN LUIS VALLEY SUBCOMMITTEE

***Phase II**: Transmission Study*
Export Capability

February 2, 2017
(Accepted by CCPG on February 16, 2017)

Studies Performed by:
San Luis Valley Subcommittee

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Executive Summary

New high-voltage transmission must be built in the south-central region of Colorado to increase electric system reliability and customer load-serving capability, and to accommodate the development of potential generation resources. The south-central region of Colorado includes the San Luis Valley (SLV) transmission system, the SLV to Poncha Springs (Poncha) transmission system, and the transmission system north and east of Poncha that connects to load-serving areas. Tri-State Generation and Transmission (Tri-State) and Public Service Company of Colorado (Public Service) agreed to jointly study the transmission issues in the south-central region of Colorado and facilitated this study effort through the SLV Subcommittee, under the purview of the Colorado Coordinated Planning Group (CCPG). The SLV Subcommittee divided the study work into two phases described below.

The Phase 1 study focused on developing transmission alternatives that would improve the transmission system between the SLV and Poncha. The Phase 1 study focused more on resolving the reliability issues in the SLV, with potential generation export capability a secondary goal. The Phase 1 study concluded that, at a minimum, an additional 230kV line is needed to meet minimum system reliability criteria. This study determined that an additional 230kV line would improve export capability by approximately 300 MW.

The Phase 2 study focused was on how best to leverage the additional 230kV line for increased generation export capability from SLV to Denver Metro. The study area was expanded to include the transmission system to the north and east of Poncha. The study evaluated several alternatives, but focused primarily on new transmission from Poncha to either Midway or Malta.

The study concluded that for either of those alternatives, the export capability could be increased by approximately another 200 MW.

The export capability can be described by the Total Transfer Capability (TTC) out of Poncha. Table 1 below lists the TTC of the transmission system out of Poncha under the various conditions studied. TTC is defined as the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. For the purposes of this study, the specified system conditions are those that meet NERC TPL-001-4 criteria both prior to and after a contingency.

Table 1: Total Transfer Capability of Export out of Poncha Substation

	2026 WestConnect Heavy Summer (MW)	2026 WECC Light Spring (MW)
Existing System	104	125
Benchmark New SLV – Poncha 230kV	426	493
Alternative 1 (North) New Poncha – Malta 230kV	617	663
Alternative 2 (East) New Poncha – W.Canon – Midway 230kV	617	973

Cost estimates

Below are indicative level cost estimates for the alternatives evaluated in this study. The cost estimates are in 2016 dollars with escalation and contingencies applied and are based upon typical construction costs for previously performed similar construction, however they have no specified level of accuracy. These estimated costs include all applicable labor and overheads associated with siting support, engineering, design, and construction of these new facilities.

Table 2. Indicative level cost estimates for Network Upgrades for Phase 1 and Phase 2

Element	Description	Cost Est. (Millions)
SLV – Poncha 230kV #2 Line[1] (Phase 1)	Construct a new 62-mile, 230kV single circuit overhead transmission line. Convert 9 miles of 69 kV to 230 kV. New 115/69 kV substation. Poncha substation additions. San Luis Valley substation additions.	**$75M**
Alternative 1: Poncha – Malta 230kV (Phase 2)	Construct approximately 52 miles of new single circuit 230kV OH transmission line. Will require new easements/ROW. New line terminations and associated equipment at Poncha and Malta Substations.	**$100M**
Alternative 2: Poncha – W.Canon – Midway 230kV (Phase 2)	Construct approximately 88 miles of new single circuit 230kV and 115kV OH transmission line. Will require new easements/ROW. New line terminations and associated equipment at Poncha, West Canon and Midway Substations.	**$170M**

[1] More comprehensive cost estimates are included for the SLV – Poncha 230 kV #2 Line as this element is further along in its development process.

I. Study Objective

As with Phase 1, there were four main objectives identified by the SLV Subcommittee. These are:

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

Since Phase 1 addressed objectives 1, 2, and 4, the purpose of Phase 2 was to determine the relative increase in export capability for a select set of transmission alternatives proposed by stakeholders through the open stakeholder process. This was done by measuring what is referred to as Total Transfer Capability (TTC) of the existing system and the increment gained by the transmission alternatives.

II. Stakeholder Process and Input

As with Phase 1, the Phase 2 study was conducted through the SLV Subcommittee of the CCPG. A kickoff meeting for Phase 2 was held in the summer of 2016, and participation has been open to all interested stakeholders. Meetings have been held regularly after the kick off meeting, generally on a monthly basis. At the kickoff meeting, the group reviewed the study plan and identified two transmission alternatives to be studied: 1) a new 230kV line from Poncha – Malta Substation; and 2) a new 230kV line from Poncha – West Canon – Midway Substation.

The transmission alternatives were added to the study plan, which was then approved to by the SLV Subcommittee in August of 2016. Public Service and Tri-State facilitated the study effort, conducted studies, and presented results. In the September SLV Subcommittee meeting, a representative from the Office of Consumer Council asked for a sensitivity study to be performed that would model the retirement of Craig unit #1. At the same meeting, a representative from Black Hills asked for a sensitivity study to be performed with their planned West Canon – West Station project in-service. The SLV Subcommittee members agreed that these sensitivities would be reasonable to include in the study. All studied alternatives and sensitivity requests are documented in this report.

All meeting materials will be posted on the Westconnect web site, under the SLV Subcommittee of CCPG[2] at the end of the study phase.

III. Background

Power is transferred to and from the SLV by two primary transmission lines: the Poncha – SLV 230kV line, which is jointly owned between Tri-State and Public Service, and the Poncha – Sargent – SLV 115kV line owned by Public Service. There is also a 69kV line between Poncha and the SLV, but it is primarily used for local load serving purposes. The 69kV line is normally operated open at Mirage Junction, rather than as a continuous delivery transmission line due to the thermal rating of the conductor. Previous studies have shown that outages on either the 115kV line or the

2 http://regplanning.westconnect.com/ccpg_san_luis_valley_sc.htm

230kV line can cause unacceptably large amounts of power to flow onto the 69kV line if it is operated as a continuous line.

Phase 1 of the SLV transmission study, completed in early 2016, evaluated seven different transmission alternatives and three sensitivities of non-transmission alternatives to improve reliability in the area and meet the key objectives of the Subcommittee. The Phase 1 study concluded that a new 230 kV line from SLV to Poncha would meet the objectives. In Phase 2 of the SLV study, the group utilized and built on top of the conclusion reached in Phase 1. This phase examined in greater detail the potential generation export capability from the SLV to regions beyond Poncha Substation.

The existing transmission in the SLV region limits the amount of generation that can be exported from the region. The SLV region has been identified as an area with good potential for solar energy generation and has been designated by Public Service to be an Energy Resource Zone as defined by Colorado Senate Bill 07-100 (SB100). SB100 was passed by the Colorado legislature in 2007. The bill requires regulated utilities in the state to 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, and to submit applications for certificates of public convenience and necessity for those plans. However, due to the same transmission constraints that limit the ability to serve load, there are also limits to how much power can be transported from SLV to Poncha, and beyond.

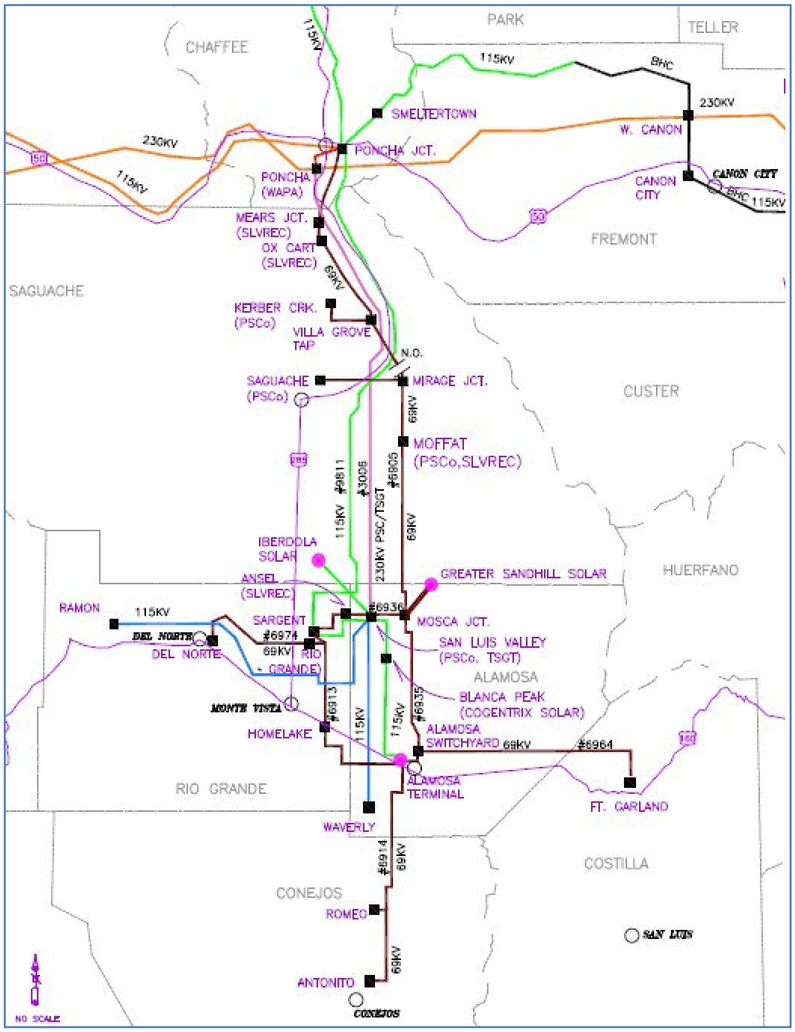


Figure 1. Area map of SLV

IV. <u>Methodology</u>

This study included power flow analyses of the current, or base transmission system and two alternatives to determine the incremental transfer capability from Poncha. TTC is defined as the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. For the purposes of this study, the specified system conditions are those that meet NERC TPL-001-4 criteria both prior to and after a contingency. Refer to Table 3 for list of transmission lines used in the TTC calculation. Note that these lines slightly differ from those measured in the SLV Phase I study, but the results are consistent. Facility loadings and voltages were monitored within the study area consistent with NERC and WECC standards. System performance should meet NERC criteria as specified in TPL-001-4 under both system normal conditions (all lines in service) and for outage, or contingency conditions (element(s) out of service). Contingency analyses will focus on the loss of a single element (N-1).

Table 3. Transmission Lines Used in the TTC Calculation

Monitored Lines	Voltage (kV)	In (-), Out (+)
Poncha - Curecanti	230	+
Poncha - MidwayBR	230	+
Poncha - Malta	115	+
Poncha - Smeltertown	115	+
Poncha - Gunnison	115	+

For each loading scenario, a benchmark analysis was performed in order to compare alternatives to benchmark conditions. There were two case scenarios selected and agreed to by the SLV Subcommittee: 2026 Westconnect Heavy Summer and 2026 Light Spring WECC approved cases. Once the benchmark cases were developed, a steady state power flow analysis was conducted for the two transmission alternatives developed by the SLV Subcommittee within the identified study area.

The sensitivity analyses included variations of the TOT 5 level, inclusion of a Black Hills' project, and the retirement of Craig 1.

A. Case Development

The first benchmark study model was derived from the Westconnect 2026 Heavy Summer case which has been reviewed and approved by members of the CCPG. The second benchmark study model was derived from the WECC approved 2026 Light Spring.

2026 Heavy Summer Westconnect D2 Case (PSS/E v33.6.0 Software Format)
- File name: 160614-26HS-WC-D2-PSSE.sav

2026 Light Spring WECC Approved (PSS/E v33.6.0 Software Format)
- File name: 26LSp1Sap.sav

B. System Topology Changes

No modification to the Topology in the benchmark cases studied.

C. Generation Modeling

No modifications were made to how generation in the power flow cases was modeled. The existing solar generation in the SLV was kept at a constant output level of 78 MW, which is approximately 60% of the nameplate rating of the existing solar generation in SLV. To model new generation, a generator was added to the San Luis 230kV bus in order to perform the Transfer Capability Study. The generation value under the Steady State Analysis Summary section represents the additional generation on top of the existing solar in the area. This method is consistent with how NERC Standard MOD-029a is performed and was agreed by the SLV Subcommittee. In order to stress transmission paths could deliver the SLV generation to the Denver Metro area, generation at Ft. St. Vrain unit 2-6, Cherokee unit 4-7, Spindle unit 1-2, and Spruce unit 1-2 were offset by the amount of additional generation added within the SLV.

At the time of this study, announcement of the retirement of Craig Unit 1 had not been made; therefore Craig Unit 1 was included in the benchmark case model. Sensitivity studies were conducted later to determine the impact of the retirement of this unit and are discussed in the Sensitivity Analysis section.

For the heavy summer benchmark case, the power flows across the transfer paths known as TOT 3 and TOT 5 were 583 MW and 355 MW, respectively. TOT 3 is the transmission path that carries power between Wyoming and Colorado. TOT 5 is the transmission path that carries power from the Western Slope of Colorado to the Front Range. The benchmark flows are typical, and represent general north to south flow for TOT 3, and west to east for TOT 5.

A detailed list of the generation in the study region (powerflow areas 70 and 73) can be found in Appendix E.

D. Load Modeling

No modifications were made to the loads that were modeled in the benchmark cases. Refer to Appendix F for a list of the loads in the SLV.

E. Line Ratings

Emergency ratings were utilized for the Colorado Springs Utilities lines (CSU) around the Briargate and Cottonwood area. Per CSU's direction emergency ratings were used for their lines to mitigate (if needed) any thermal constraints arising from N-1 events.

F. Export Capability

Export capability was measured in terms of TTC. For this study, the TTC was defined as the sum of the flows on the transmission lines emanating from Poncha to the west, north and east. Note, the transfer capability analysis in the SLV Phase I study only focused on the transmission system between SLV and Poncha, and thus the TTCs in this study are slightly different.

G. Criteria

As a general rule, the following system parameters were monitored during the study and are tabulated in this report as needed:

1. All buses, lines, and transformers with base voltages equal to or greater than 69kV in the Colorado power flow Areas 70 and 73 were monitored in all study cases.
2. Post contingency element loadings were only tabulated when an element rating was exceeded and the loading increase was at least 1% from the normal system loading. Specifically, if an element was overloaded in the normal condition and increased no more than 1% in the outage condition, the overload was not reported.
3. Voltages were monitored per NERC /WECC criteria of 0.9 – 1.1 p.u. Deviation was monitored based on WECC criteria of 0.8 p.u. Low/High voltages were not required to be below/above 0.9/1.1 and have a deviation of 8% or greater.

The SLV Subcommittee adhered to the following criteria for these load flow studies:

- **Category P0 – System Normal**
  "N-0" System Performance Under Normal (No Contingency) Conditions
  NERC Standard TPL-001-4

Voltage:	0.95 to 1.05 per unit
Line Loading:	100 percent of continuous rating
Transformer Loading:	100% of highest 65 °C rating

  Manual or automatic system adjustments such as shunt capacitor or reactor switching, generator scheduling, or LTC tap adjustment are allowed. Area interchanges and phase shifter adjustments are allowed.

- **Category P1 – Loss of generator, line, or transformer (Forced Outage)**
  "N-1" System Performance Following Loss of a Single Element
  NERC Standard TPL-001-4

Voltage:	0.90 to 1.10 per unit
Line Loading:	100 percent of continuous rating.

  Manual system adjustments such as generation dispatch will not be allowed. Area interchange adjustments will not be allowed. Adjustments of shunt capacitors or reactors, phase shifting transformers and load tap changing (LTC) transformers will not be allowed.

- **Category P2 – P7 – Multiple contingency outages**
  Multiple contingency outages – Refer to the NERC contingency table in Reliability Standard
  NERC Standard TPL-001-4

Voltage:	0.90 to 1.10 per unit
Line Loading:	100 percent of continuous rating.

  Manual system adjustments such as generation dispatch will not be allowed. Area interchange adjustments will not be allowed. Adjustments of shunt capacitors or reactors, phase shifting transformers and load tap changing (LTC) transformers will not be allowed.

H. Steady State Power Flow

The benchmark and alternative studies focused on the North American Electric Reliability Corporation (NERC) Category P0 (system intact, N-0) and NERC Category P1 (single contingency, N-1) performance.

A list of the contingency file, subsystem file, and monitor file can be found in Appendix C.

Studies monitored loading and voltages on elements within Area 70 and 73, consistent with NERC, WECC standards and criteria as outlined in the study methodology.

For all contingency analyses the following solution parameters were selected:

- Tap Adjustment - Lock Taps
- Area Interchange Control - Off
- Switched Shunt Adjustments - Lock All
- Adjust DC taps
- Solution Engine - Full Newton-Raphson

All studies were performed through the SLV Subcommittee of the CCPG with Public Service and Tri-State acting as the study facilitators. Steady state power flow and voltage analysis was performed using Siemen's PSS/E v33.6.0 software.

V. Studies

A. Benchmark

The power flow analyses (steady state with single contingency) were performed on two benchmark cases to determine the benchmark TTC: 2026 Heavy Summer and 2026 Light Spring. The loads and generation levels in the SLV are shown below for the two benchmark cases.

Table 4. Loads and Generations for Benchmark Cases

	SLV Loads (MW)	SLV Gen (MW)
2026HS	134	78
2026LSp	56	83

B. Alternatives

In order to deliver generation from the SLV to the Front Range, there are a limited number of reasonable paths for new transmission to be developed. As a result, the SLV Subcommittee limited the potential transmission alternatives to study.

C. Alternatives Considered but Not Modeled

Below are some transmission alternatives that were considered by the SLV Subcommittee, but not evaluated through the technical study process.

West Alternative:

Due to the geography of the region, there are only three potential transmission paths for delivering power out of Poncha. These are paths that could utilize existing transmission corridors, and the transmission corridors run west, north and east. The north and east alternatives were considered for study and are described in subsequent sections. The option of going to the west from Poncha was eliminated, since it would not result in a direct path to the Front Range load area, where most of the PSCo and Tri-State loads are located. As a result, this would not be a beneficial or cost effective alternative.

Combined Northern Alternative (Alt-1) and Eastern Alternative (Alt-2)

At the stakeholder meeting in September, a third alternative was proposed to be studied by a member of the group. The third alternative is the combination of alternative 1 and alternative 2: a single 230kV circuit from Poncha – Malta Substation and a single 230kV circuit from Poncha – West Canon – Midway Substation. The limitations found in the alternative 1 and alternative 2 were outside of the area of study, therefore, the group did not believe that alternative 3 was a reasonable option for this phase.

D. Studied Alternatives

Alternatives were developed and agreed to by the SLV Subcommittee based on the existing transmission and the natural flow of power from SLV to the Denver Metro area. Table 5 below lists the developed transmission alternatives that were studied:

Table 5. Study Alternatives List

Case Label	Alt. No.	Description
Pre-BM	0	Existing System
BM	0	Benchmark case (with new SLV – Poncha 230kV)
Alt-1	1	Poncha - Malta 230kV line
Alt-2	2	Poncha - W.Canon - MidwayPS 230kV line
Alt-1A	1	Poncha - Malta 230kV line and W.Canon - W.Station 115kV line
Alt-2A	2	Poncha - W.Canon - MidwayPS 230kV line and W.Canon - W.Station 115kV line

Alternative 1: Approximately 52 miles of new single circuit 230kV overhead transmission line from Poncha to Malta Substation.

Alternative 2: Approximately 88 miles of new single circuit 230kV overhead transmission line from Poncha to West Canon to Midway Substation.

Refer to Appendix A for drawings depicting the two alternatives.

E. Benchmark and Selected Alternatives Analysis

Steady state power flow analyses were conducted for the developed benchmark case and for select transmission system alternatives developed and agreed to by the SLV Subcommittee within the identified study area.

F. Steady State Analysis Summary

The study was to determine the TTC of the benchmark scenario and each of the alternatives. In order to determine the TTC, a generator was added to the SLV 230kV to serve as a source and the generation was sank to the Denver area generators at various locations such as Ft. St. Vrain, Spindle, and Spruce. During the single contingency simulation, the added generator at SLV 230kV was increased until a thermal limit at any transmission facility was reached. The outage facility was then put back into service, and the summation of flow on all five monitored lines was taken to be considered for the TTC.

2026 Heavy Summer Case

1) Pre-Benchmark case (existing system)

In order to understand the significance of the benchmark value and how much TTC a new Poncha – SLV 230kV line can provide, a pre-benchmark (pre-BM) study was performed. Using the same methodology to calculate the TTC, the TTC for the pre-BM of the 2026HS is 104 MW and 125 MW for the 2026LSp. The limiting element for the two cases was found to be the 115kV line between Poncha – SLV, which is paralleling the existing 230kV line. Adding an additional 230kV line, as found in Phase 1, will have many benefits and one of which is increasing the TTC up to Poncha. The new 230kV line will shift the limiting element from inside the SLV to outside of the SLV. Note that the values in this study are consistent, but differ slightly from the values listed in the Phase I study due to differences in where the values were measured.

2) Benchmark case

In Phase 2 study, the benchmark case assumed a new Poncha – SLV 230kV line was built. Below are three injection levels for the benchmark case. Note that the added generation column is the amount of generation added on top of the existing generation in the case (78 MW).

The first apparent limit found was due to a breaker current transformer (CT), line trap, and relays (also known as terminal equipment) at the Poncha substation. This is shown in Table 6-8 below, with the limiting element being the Poncha – Smeltertown 115kV line. Replacing or adjusting this equipment would increase the line rating to 120 MVA. As terminal equipment upgrades have relatively minor costs, it was assumed that they could be upgraded for the purposes of this study. Therefore, the 320 MW level was considered a “soft limit”, and the SLV generation was increased beyond that level.

The next limiting conditions occurred at around 500 MW of added generation which yielded 426 MW of TTC. As seen in Tables 7 & 8, there were three issues identified at the 500 MW level. These were the outage of PonchaBR-W.Canon 230kV overloads the Ray Lewis-Buena Vista 115kV line, outage of SLV-Sargent 115kV overloads the Alamosa 115/69kV bank, and outage of Curecanti-Lost Canyon 230kV overloads the Curecanti-South Canal 115kV line.

Table 6. Limiting Element: Poncha – Smelter town 115kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
BM	320	252	Poncha-Smeltertown 115kV	PonchaBR-W.Canon 230kV	100%	60*

- Derated due to Breaker CT at Poncha Junction. Replacing Breaker CT, Line Trap, and Relays at Poncha Junction will increase the line rating to 600 Amps (120 MVA).

Table 7. Limiting Element: Ray Lewis – Buena Vista 115kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
BM	500	426	Ray Lewis-Buena Vista 115kV	PonchaBR-W.Canon 230kV	101%	115*

- Conductor rating @ 90 degree F, highest historical average for July at Poncha Springs

Table 8. Limiting Element: Alamosa 115/69kV Transformer

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
BM	500	426	Alamosa 115/69 kV Bank #1	SLV-Sargent 115 kV	100%	25*
BM	500	426	Curecanti-South Canal 115 kV	Curecanti-Lost Canyon 230 kV	100%	137

- The current transformer rating of Alamosa 115/69 kV is 25 MVA. There is a plan to replace this bank with an 84 MVA bank by end of 2016.

The Ray Lewis – Buena Vista and Curecanti – South Canal 115 kV line loadings were considered to be limiting conditions. Therefore, the highest TTC for the benchmark was 426 MW.

3) Alternative 1: New Poncha – Malta 230kV line

The same process of determining system limitations was performed for each transmission alternative. Apparent "soft limits" were found for these simulations such as the breaker CT at Poncha Junction and 25 MW rating of Alamosa 115/69kV transformer. The hard limit in this case is the Curecanti – South Canal 115kV line rated at 137 MVA. These are shown in Tables 9-11.

Table 9. Limiting Element: Poncha – Smeltertown 115kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
Alt-1	400	329	Poncha-Smeltertown 115kV	PonchaBR-W.Canon 230kV	100%	60*

- De-rated due to Breaker CT at Poncha Junction. Replacing Breaker CT, Line Trap, and Relays at Poncha Junction will increase the line rating to 600 Amps (120 MVA).

Table 10. Limiting Element: Alamosa 115/69kV Transformer

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
Alt-1	550	474	Alamosa 115/69kV Bank #1	SLV-Sargent 115kV	100%	25*

- The current transformer rating of Alamosa 115/69kV is 25 MVA. There is a plan to replace this bank with an 84 MVA bank by end of 2016.

Table 11. Limiting Element: Ray Lewis – Buena Vista 115kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
Alt-1	700	617	Ray Lewis-Buena Vista 115kV	PonchaBR-Malta 230kV	100%	115*
Alt-1	700	617	Curecanti-South Canal 115kV	Curecanti-Lost Canyon 230kV	100%	137

- Conductor rating @ 90 degree F, highest historical average for July at Poncha Springs

The Ray Lewis – Buena Vista and Curecanti – South Canal 115 kV line loadings were considered to be limiting conditions. Therefore, the highest generation level for the Poncha – Malta alternative was 700 MW, which corresponded to a 617 MW TTC.

4) Alternative 2: New Poncha – W.Canon - MidwayPS 230kV line

Adding the new Poncha – W.Canon - Midway 230kV line increases the added generation to 700 MW, which yields 617 MW of TTC. Similar soft limit was found for these simulations such as 25 MW rating of Alamosa 115/69kV transformer. For the east alternative, overloads in the Colorado Springs Utilities (CSU) system were observed around the Briargate and Cottonwood areas. Per CSU's comments during one of the stakeholder's meeting, emergency line rating can be used to mitigate line overload for CSU's system under single contingency. Another acceptable operating practice is to open up the Monument – Palmer Lake 115kV line to mitigate the overload around that area. The hard limit in this case is also the Curecanti – South Canal 115kV line with the rating of 137 MVA.

Table 12. Limiting Element: Alamosa 115/69kV Transformer

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
Alt-2	350	280	Alamosa 115/69kV Bank #1	SLV-Sargent 115kV	100%	25*

- The current transformer rating of Alamosa 115/69kV is 25 MVA. There is a plan to replace this bank with an 84 MVA bank by end of 2016.

Table 13. Limiting Element: BRIARGATE S – CTTNWD S 115 kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
Alt-2	600	522	BRIARGATE S-CTTNWD S 115kV	CTTNWD N-KETTLECK S 115kV	100%	150

- CSU's emergency rating for this line is 192 MVA. Per CSU's direction, using e-rating for CSU line under single contingency is acceptable.

Table 14. Limiting Element: Curecanti – South Canal 115kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
Alt-2	700	617	Curecanti-South Canal 115kV	Curecanti-Lost Canyon 230kV	101%	137

<u>2026 Light Spring Case, 56 MW of Load, 83 MW of Gen</u>

Similar studies were done for the 2026 Light Spring case with lower loading condition. When the load is lower, particularly in the SLV area, the export capability will be higher due to the single outlet coming out of the valley.

1) Benchmark case with Black Hills' Project

Table 15. Limiting Element: Poncha – Smelter town 115kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
BM-A	275	287	Poncha-Smeltertown 115kV	PonchaBR-W.Canon 230kV	100%	60*

- De-rated due to Breaker CT at Poncha Junction. Replacing Breaker CT, Line Trap, and Relays at Poncha Junction will increase the line rating to 600 Amps (120 MVA).

Table 16. Limiting Element: Ray Lewis – Buena Vista 115kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
BM-A	450	448	Ray Lewis-Buena Vista 115 kV	PonchaBR-W.Canon 230 kV	100%	115*

- Conductor rating @ 90 degree F, highest historical average for July at Poncha Springs

Table 17. Limiting Element: W.Canon 230/115kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
BM-A	500	493	W.Canon 230/115kV	W.Canon-MidwayBR 230kV	99%	100

Table 18. Limiting Element: Curecanti-S.Canal 115kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
BM-A	850	787	Curecanti-S.Canal 115kV	Curecanti-Lost Canyon 230kV	100%	137

2) Alternative 1A: New Poncha – Malta 230kV line

Table 19. Limiting Element: Poncha – Smeltertown 115kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
Alt1-A	380	398	Poncha-Smeltertown 115kV	PonchaBR-W.Canon 230kV	100%	60*

- De-rated due to Breaker CT at Poncha Junction. Replacing Breaker CT, Line Trap, and Relays at Poncha Junction will increase the line rating to 600 Amps (120 MVA).

Table 20. Limiting Element: Ray Lewis – Buena Vista 115kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
Alt-1A	660	663	Ray Lewis-Buena Vista 115kV	PonchaBR-Malta 230kV	100%	115*

- Conductor rating @ 90 degree F, highest historical average for July at Poncha Springs

Table 21. Limiting Element: Curecanti-S.Canal 115kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
Alt-1A	1000	973	Curecanti-South Canal 115kV	Curecanti-Lost Canyon 230kV	98%	137

3) Alternative 2A: Poncha – W.Canon - MidwayPS 230kV and W.Canon – W.Station 115kV line

Table 22. Limiting Element: Curecanti – South Canal 115kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
Alt-2A	1000	973	Curecanti-South Canal 115kV	Curecanti-Lost Canyon 230kV	100%	137

The Ray Lewis – Buena Vista and Curecanti – South Canal 115 kV line loadings were considered to be limiting conditions for the 2026 Light Spring case. Therefore, the highest generation level for the both alternatives was 1000 MW, which corresponded to a 973 MW TTC.

VI. Sensitivity Analyses

As mentioned previously, additional sensitivity analyses were conducted at the suggestions of participants of the SLV Subcommittee to better understand the impact they would have on the transmission system. The sensitivities were performed using the benchmark case and the alternatives of the 2026 Heavy Summer.

A. List of Sensitivity Analyses

The list below describes the sensitivities that were developed and agreed to be studied by the SLV Subcommittee.

1. Alternative 1A case with Craig unit 1 Retirement Analysis
2. Benchmark case with Black Hills' West Canon – West Station 115kV line (BM-A)
3. Alternative 1 case with Black Hills' West Canon – West Station 115kV line (Alt-1A)
4. Alternative 2 case with Black Hills' West Canon – West Station 115kV line (Alt-2A)
5. Stressed TOT 5 Analysis

The sensitivity analysis was conducted in the same manner as the steady state power flow using the same methodology and criteria.

B. Sensitivity Analyses Results

1) Craig Unit 1 Retirement Analysis

In September 2016, an announcement was made that Craig Unit 1 would be shut down by 2025. Because this date was prior to the study case date, a member of the SLV Subcommittee requested a sensitivity analysis of the Craig Unit 1 retirement.

The analysis for the Craig Unit 1 retirement sensitivity explored a single generation dispatch scenario and used the Alternative 2A 700 MW power flow case as a benchmark.

A contingency analysis was performed for each of the additional sensitivities, and the results were compared in a side-by-side analysis with the Benchmark case and the Craig Unit 1 retirement sensitivity.

From these results the SLV Subcommittee concluded that there was no significant impact due to the retirement of Craig Unit 1 to the study areas and the transfer capability of the two alternatives.

The Craig Unit 1 Retirement Analysis can be found in Appendix G.

2) Impact of the Black Hills West Canon – West Station Project

Black Hills has plans to construct a 115kV transmission line between West Canon and West Station to increase system reliability around the area and serve new load at North Canyon Substation by 2019. This project changes the transmission topology of the path between Poncha and the Front Range, and therefore has the potential to impact the Transfer Capability. Since Black Hills has indicated this is a "planned" project, this would normally be included in the benchmark models. However, since the project was not included in the benchmark, the group agreed to evaluate the project as sensitivity. This sensitivity study was performed for both the heavy summer and the light spring cases.

The study results, shown in Tables 23-28 below, indicated that there was no significant impact to the Total Transfer Capability values due to the Black Hills project. However, the models used for these studies showed minimal power flow on the West Canon – West Station 115kV line. This may be due to the dispatch used in order to increase flows from west to east. Based on Black Hills studies, the benefits of the project is primarily demonstrated under system conditions where power is dispatched from east to west to reliably serve loads around the Canyon City area.

2026 Heavy Summer Case

a) Benchmark A

Table 23. Limiting Element: Ray Lewis – Buena Vista 115kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
BM-A	500	426	Ray Lewis-Buena Vista115kV	PonchaBR-W.Canon 230kV	101%	115*

- Conductor rating @ 90 degree F, highest historical average for July at Poncha Springs

Table 24. Limiting Element: Alamosa 115/69kV Transformer)

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
BM-A	500	426	Alamosa 115/69kV Bank #1	SLV-Sargent 115kV	100%	25*
BM-A	500	426	Curecanti-South Canal 115kV	Curecanti-Lost Canyon 230kV	100%	137

- The current transformer rating of Alamosa 115/69kV is 25 MVA. There is a plan to replace this bank with an 84 MVA bank by end of 2016.

b) Alternative 1A

Table 25. Limiting Element: Alamosa 115/69 kV Transformer

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
Alt-1A	550	474	Alamosa 115/69kV Bank #1	SLV-Sargent 115kV	100%	25*

- The current transformer rating of Alamosa 115/69kV is 25 MVA. There is a plan to replace this bank with an 84 MVA bank by end of 2016.

Table 26. Limiting Element: Ray Lewis – Buena Vista 115 kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
Alt-1A	700	617	Ray Lewis-Buena Vista 115 kV	PonchaBR-Malta 230 kV	100%	115*
Alt-1A	700	617	Curecanti-South Canal 115kV	Curecanti-Lost Canyon 230kV	100%	137

- Conductor rating @ 90 degree F, highest historical average for July at Poncha Springs

c) Alternative 2A

Table 27. Limiting Element: BRIARGATE S – CTTNWD S 115kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
Alt-2A	600	522	BRIARGATE S-CTTNWD S 115kV	CTTNWD N-KETTLECK S 115kV	99%	150

- Colorado Springs Utilities line; can be operated up to Emergency Rating of 192 MVA under N-1 contingency. This overload will longer be valid.
- An operating practice would be opening up Palmer – Monument 115 kV which will reduce the flow by 10%.

Table 28. Limiting Element: Curecanti – South Canal 115kV

Case	Added Gen	TTC (MW)	Limiting Element	Contingency	% Load	Element Rating (MVA)
Alt-2A	700	617	Curecanti-South Canal 115 kV	Curecanti-Lost Canyon 230 kV	101%	137
Alt-2A	700	617	BRIARGATE S-CTTNWD S 115 kV	CTTNWD N-KETTLECK S 115 kV	101%	150

3) Stressed TOT 5 Analysis

WECC Path 39 (TOT 5) is a set of lines that delineating the separation between Eastern and Western Colorado across the Rocky Mountain Divide with defined transfer limit of 1680 MW west to east. This corridor enables the transmission of remote generation located in Western Colorado to loads located along the Front Range.

TOT 5 consists of eight transmission lines:

- North Park – Terry Ranch Road 230 kV
- Craig – Ault 345 kV
- Hayden – Gorepass 230 kV
- Hayden – Gorepass 138 kV
- N. Gunnison – Poncha 115kV
- Curecanti – Poncha 230 kV
- Basalt – Malta 230 kV
- Hopkins – Malta 230 kV

As TOT 5 is only defined in the west to east direction, it was the only direction of flow studied and was stressed by increasing generation in the north and south parts of Western Colorado, utilization of the Shiprock and Waterflow Phase Shifting Transformers and reducing generation along the Front Range. Three levels of stressing on TOT 5 beyond the original base case were evaluated: 1000 MW, 1100 MW, and 1200 MW. Inter-Area transfers were preserved within the study footprint.

Tables outlining the case, amount of generation added, limiting element and limiting contingency, percent loading on the element, and element rating can be found in Appendix H.

From the tables, in Appendix H, it was concluded that an increase in west to east transfers across TOT 5 results in a decrease in the ability to export generation from SLV to the Denver Metro Area dependent on the Phase 2 Alternative modeled. Due to the limited number of TOT 5 stress levels modeled, a specific relationship between TOT 5 level and SLV generation is not identified. This sensitivity was solely intended to highlight that a relationship exists and is dependent on the type of generation and the location of the interconnection request which is to be evaluated separately through the interconnection study process.

VII. Conclusion

The purpose of these Phase 2 studies was to determine the transfer capability of the existing system and transmission alternatives beyond Poncha Substation using a comparative analysis approach. The comparative analysis approach provides an incremental value of each alternative based on the benchmark case. The TTC values in this report are only valid under the set of conditions and assumptions made for this study.

Phase 2 indicates that the existing TTC of the SLV area is approximately 104 MW with the limiting element being the 115kV line between Poncha – SLV paralleling the 230kV Poncha – SLV line. Adding an additional 230kV line between Poncha – SLV could increase the TTC to approximately 426 MW, for an increase of about 300 MW.

Alternative 1, which would implement a new 230 kV line from Poncha to Malta would increase the TTC to 617 MW, which provides an increment of about 190 MW.

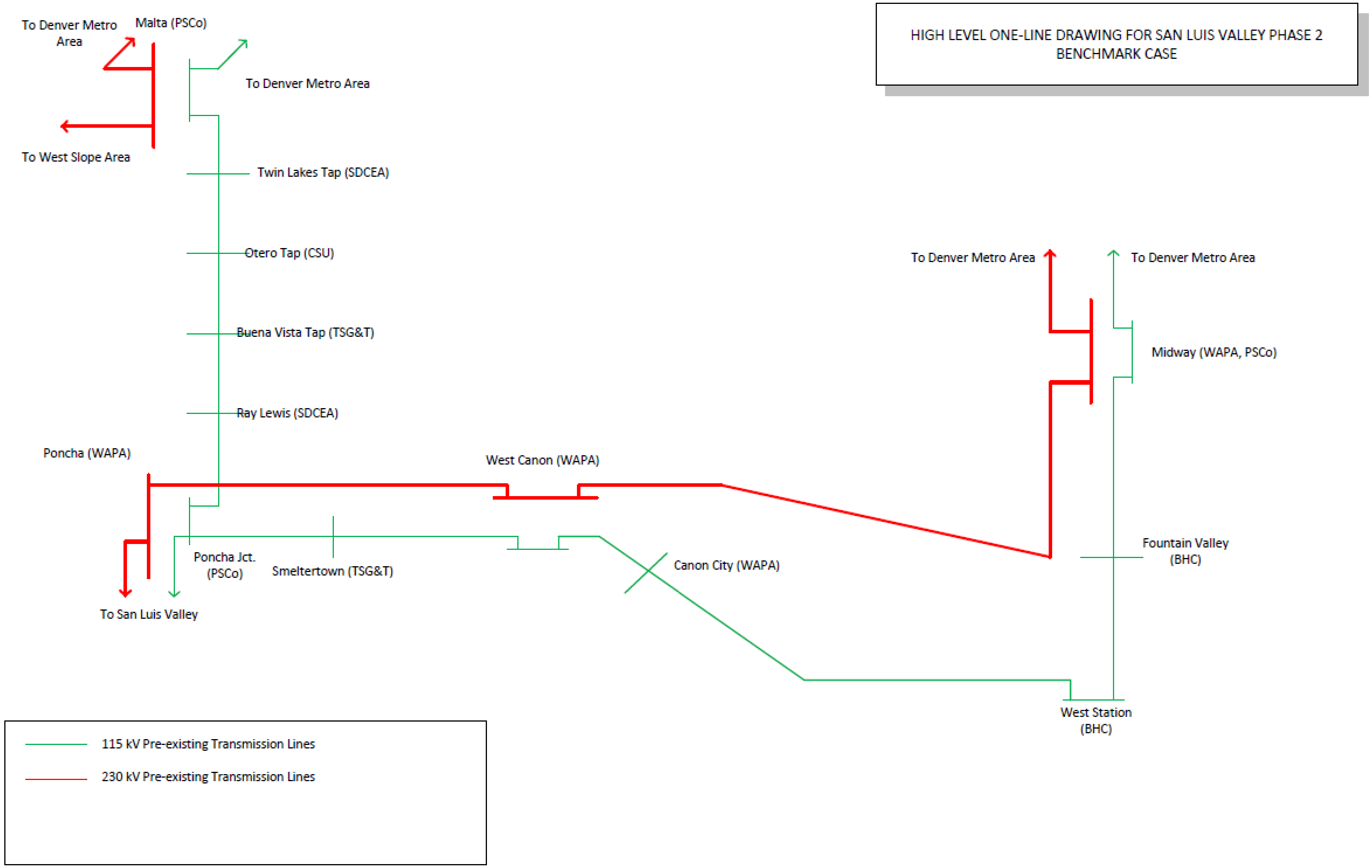
Alternative 2, which would implement a new 230 kV line from Poncha to Midway would increase the TTC to 617 MW, which provides an increment of about 190 MW.

Both alternative 1 and 2 assumed the additional 230kV line between Poncha – SLV is built. Also, both alternatives yield identical increment of TTC.

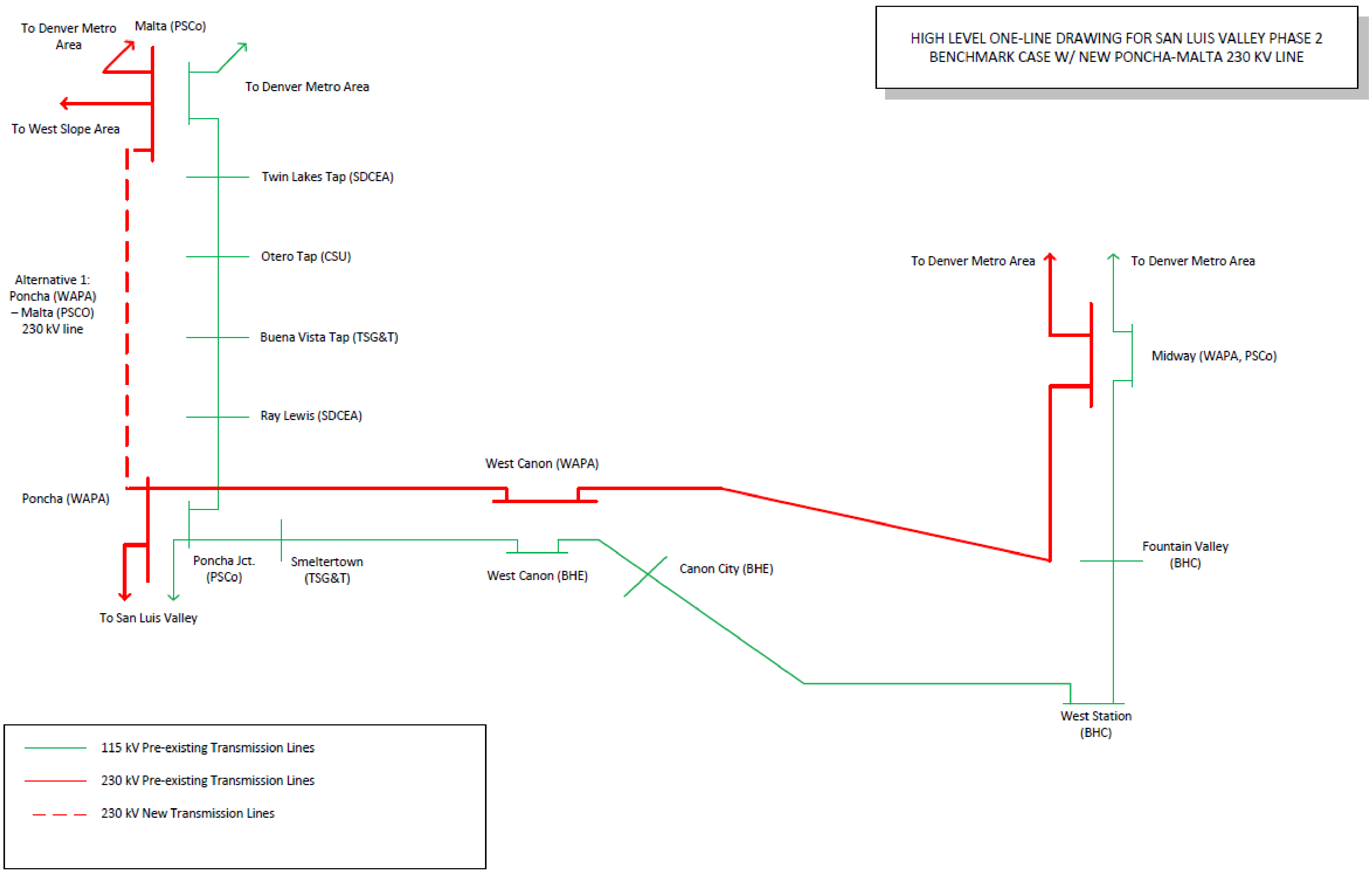
On February 16, 2017, the CCPG agreed that this report met the objectives of the scope, and the results were technically adequate and accurate.

APPENDIX A: Simple Drawings of Benchmark and Alternatives

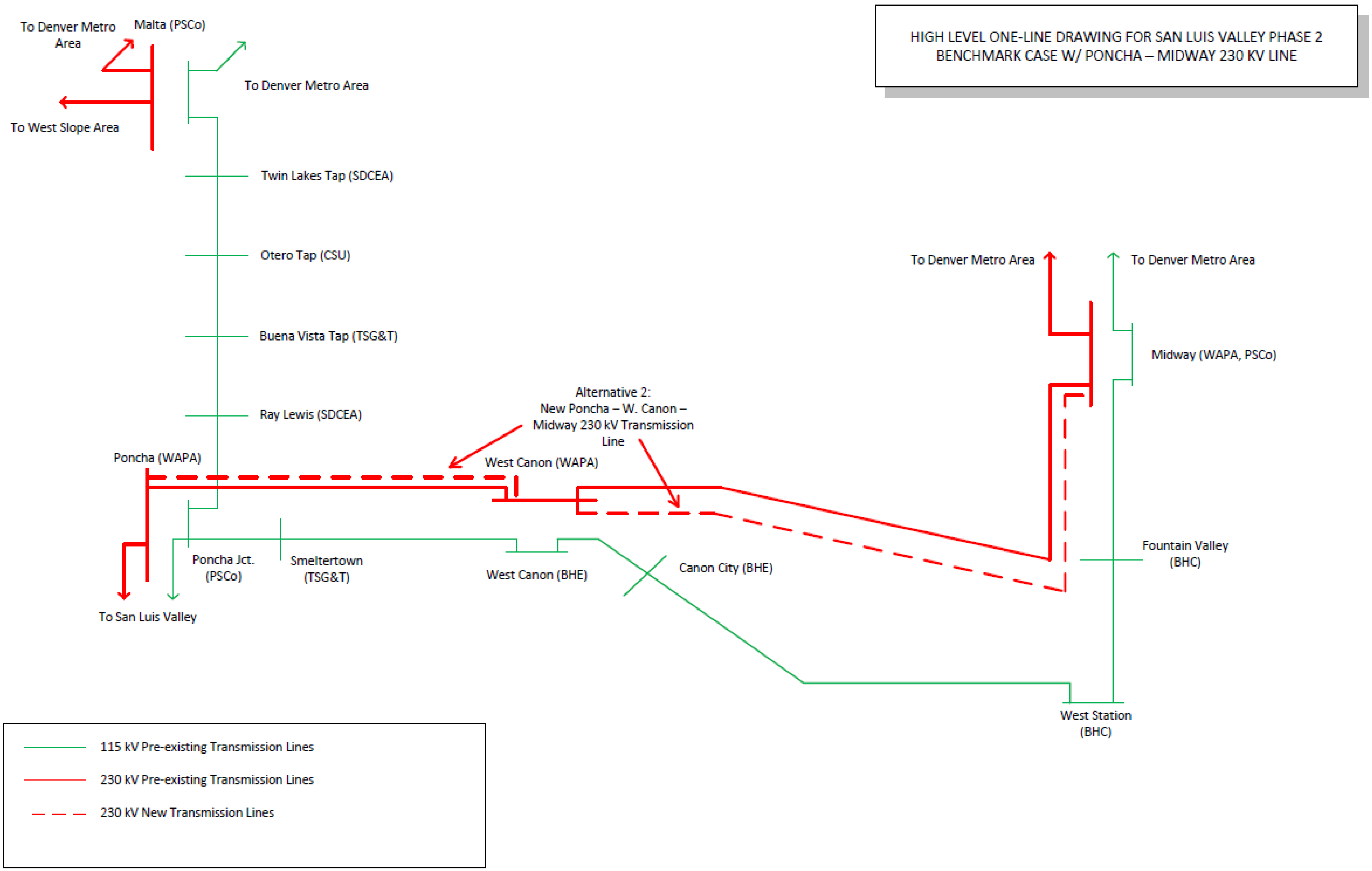
Benchmark Case



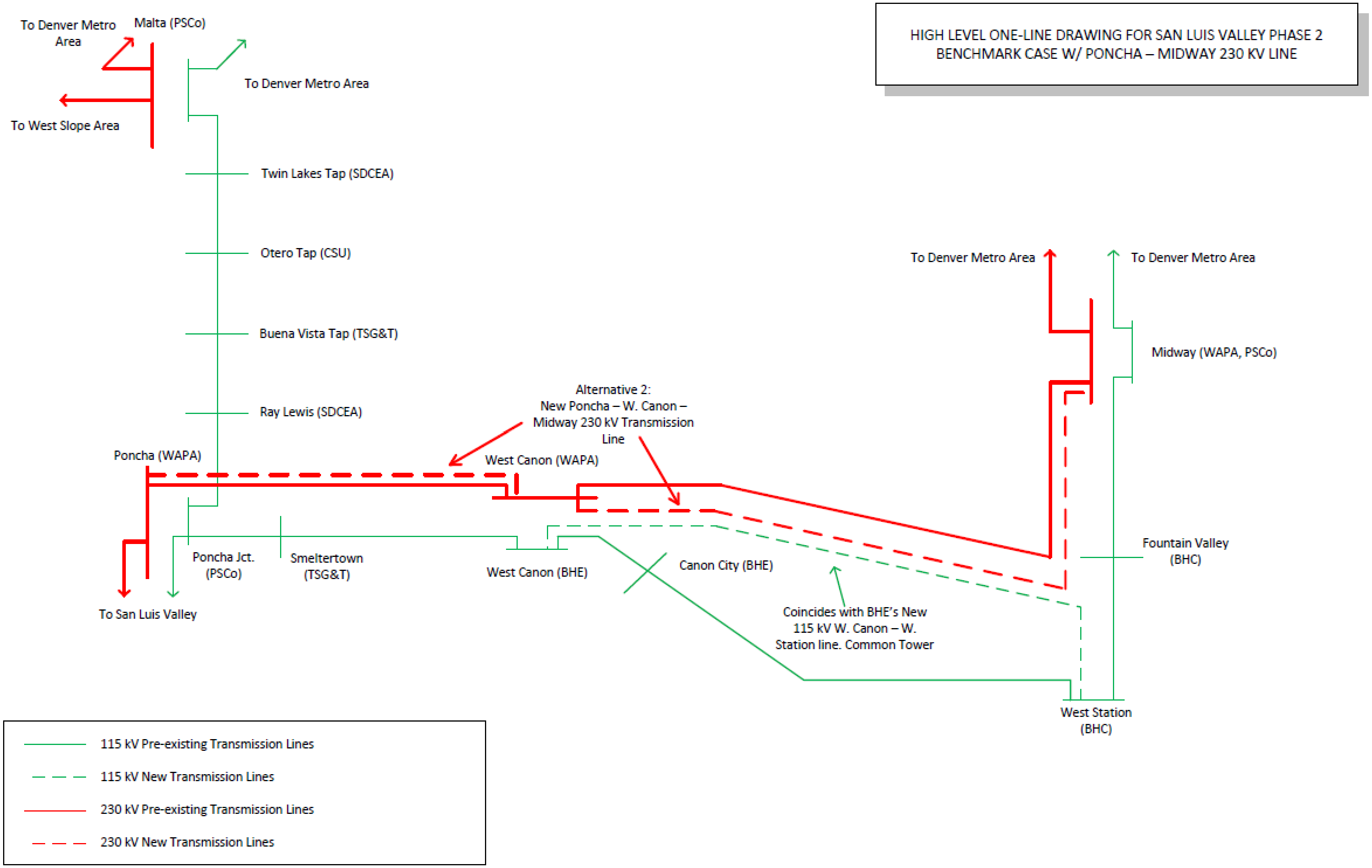
Alternative 1



Alternative 2

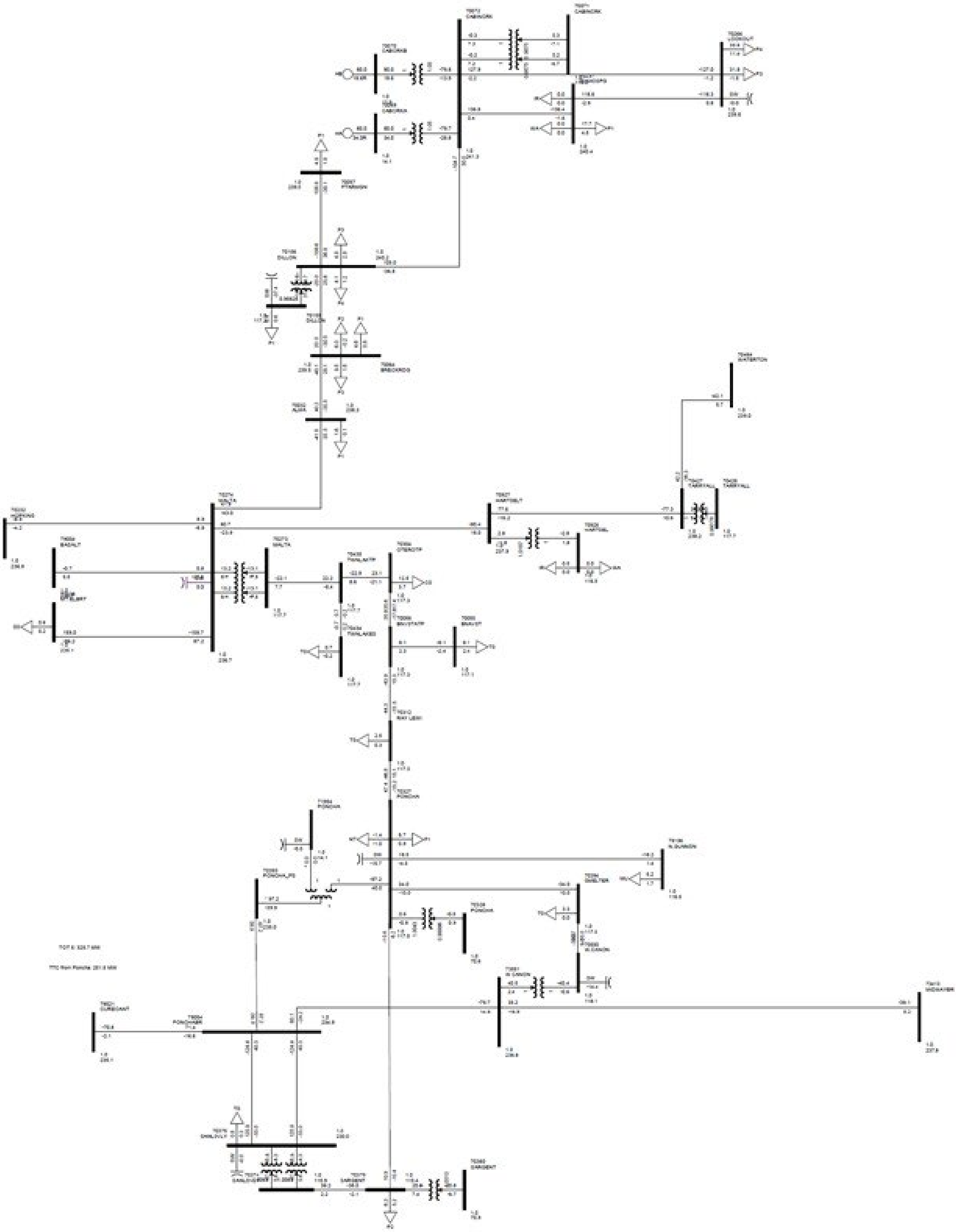


Alternative 2 with Black Hills W.Canon – W.Station 115kV Project

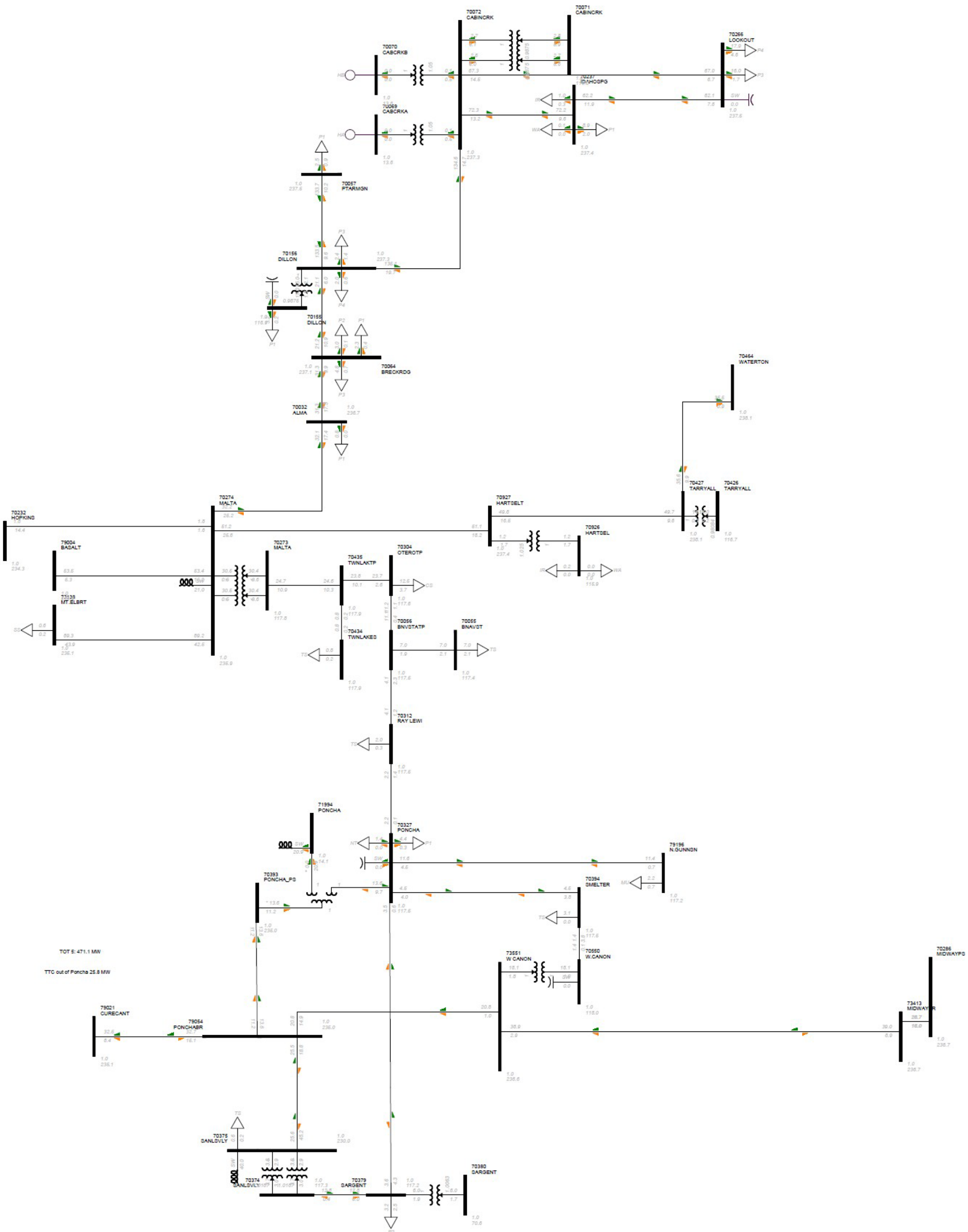


APPENDIX B: PSS/E Slider Files for 2026HS and 2026LSp

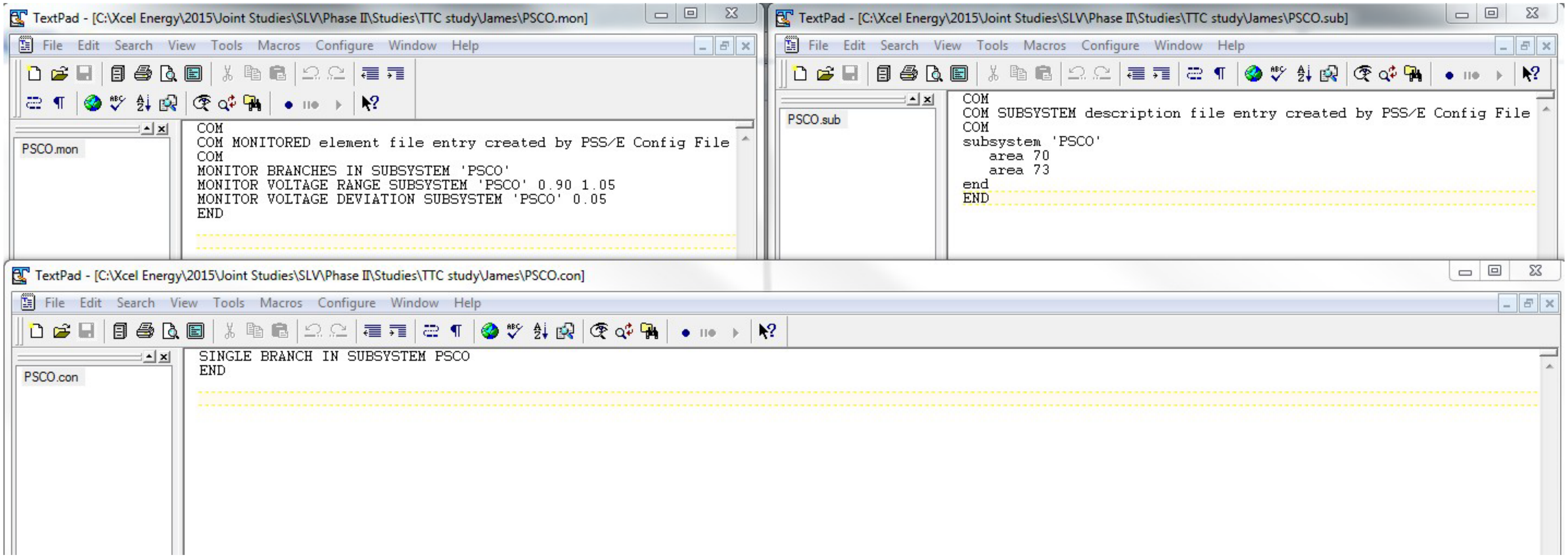
2026 Heavy Summer PSS/E Slider Diagram



2026 Light Spring PSS/E Slider Diagram



APPENDIX C: PSS/E Steady State Automation Files



APPENDIX D: PSS/E Change Files for Alternatives and Sensitivity

PSS/E code for adding Poncha – Malta 230kV

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RDCH
1
0 / END OF BUS DATA, BEGIN LOAD DATA
0 / END OF LOAD DATA, BEGING FIXED BUS SHUNT DATA
0 / END OF FIXED BUS SHUNT DATA, BEGIN GENERATOR DATA
0 / END OF GENERATOR DATA, BEGIN BRANCH DATA
79054, 70274, '1', 0.007475651, 0.064772342, 0.180600851, 576,576,576, 0.0, 0.0, 0.0, 0.0, 1, 1, 52.0, 65, 1.00 /Poncha to Malta 230kV
0 / END OF BRANCH DATA, BEGIN TRANSFORMER DATA
0 / END OF TRANSFORMER DATA, BEGIN AREA DATA
0 / END OF AREA DATA, BEGIN TWO-TERMINAL DC DATA
0 / END OF TWO-TERMINAL DC DATA, BEGIN VSC DC LINE DATA
0 / END OF VSC DC LINE DATA, BEGIN IMPEDANCE CORRECTION DATA
0 / END OF IMPEDANCE CORRECTION DATA, BEGIN MULTI-TERMINAL DC DATA
0 / END OF MULTI-TERMINAL DC DATA, BEGIN MULTI-SECTION LINE DATA
0 / END OF MULTI-SECTION LINE DATA, BEGIN ZONE DATA
0 / END OF ZONE DATA, BEGIN INTER-AREA TRANSFER DATA
0 / END OF INTER-AREA TRANSFER DATA, BEGIN OWNER DATA
0 / END OF OWNER DATA, BEGIN FACTS DEVICE DATA
0 / END OF FACTS DEVICE DATA, BEGIN SWITCHED SHUNT DATA
0 / END OF SWITCHED SHUNT DATA, BEGIN GNE DATA
0 / END OF GNE DATA, BEGIN INDUCTION MACHINE DATA
0 / END OF INDUCTION MACHINE DATA


/Notes:
/       End of Data

ECHO
@END
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PSS/E code for adding Poncha – W.Canon 230kV

```
RDCH
1
0 / END OF BUS DATA, BEGIN LOAD DATA
0 / END OF LOAD DATA, BEGING FIXED BUS SHUNT DATA
0 / END OF FIXED BUS SHUNT DATA, BEGIN GENERATOR DATA
0 / END OF GENERATOR DATA, BEGIN BRANCH DATA
79054,73551,'2', 0.006471536, 0.051500722, 0.178546399, 1115.0, 1115.0, 1115.0, 0.0, 0.0, 0.0, 0.0, 1, 1, 46.2, 65, 1.00 /Poncha to W.Canon 230kV
0 / END OF BRANCH DATA, BEGIN TRANSFORMER DATA
0 / END OF TRANSFORMER DATA, BEGIN AREA DATA
0 / END OF AREA DATA, BEGIN TWO-TERMINAL DC DATA
0 / END OF TWO-TERMINAL DC DATA, BEGIN VSC DC LINE DATA
0 / END OF VSC DC LINE DATA, BEGIN IMPEDANCE CORRECTION DATA
0 / END OF IMPEDANCE CORRECTION DATA, BEGIN MULTI-TERMINAL DC DATA
0 / END OF MULTI-TERMINAL DC DATA, BEGIN MULTI-SECTION LINE DATA
0 / END OF MULTI-SECTION LINE DATA, BEGIN ZONE DATA
0 / END OF ZONE DATA, BEGIN INTER-AREA TRANSFER DATA
0 / END OF INTER-AREA TRANSFER DATA, BEGIN OWNER DATA
0 / END OF OWNER DATA, BEGIN FACTS DEVICE DATA
0 / END OF FACTS DEVICE DATA, BEGIN SWITCHED SHUNT DATA
0 / END OF SWITCHED SHUNT DATA, BEGIN GNE DATA
0 / END OF GNE DATA, BEGIN INDUCTION MACHINE DATA
0 / END OF INDUCTION MACHINE DATA

/Notes:
/       End of Data

ECHO
@END
```

PSS/E code for adding Poncha – W.Canon 230kV

```
RDCH
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0 / END OF BUS DATA, BEGIN LOAD DATA
0 / END OF LOAD DATA, BEGING FIXED BUS SHUNT DATA
0 / END OF FIXED BUS SHUNT DATA, BEGIN GENERATOR DATA
0 / END OF GENERATOR DATA, BEGIN BRANCH DATA
73551,70286,'1', 0.005883215, 0.046818837, 0.167928214, 1115.0, 1115.0, 1115.0, 0.0, 0.0, 0.0, 0.0, 1, 1, 46, 65, 1.00 /W.Canon - MidwayBR 230kV
0 / END OF BRANCH DATA, BEGIN TRANSFORMER DATA
0 / END OF TRANSFORMER DATA, BEGIN AREA DATA
0 / END OF AREA DATA, BEGIN TWO-TERMINAL DC DATA
0 / END OF TWO-TERMINAL DC DATA, BEGIN VSC DC LINE DATA
0 / END OF VSC DC LINE DATA, BEGIN IMPEDANCE CORRECTION DATA
0 / END OF IMPEDANCE CORRECTION DATA, BEGIN MULTI-TERMINAL DC DATA
0 / END OF MULTI-TERMINAL DC DATA, BEGIN MULTI-SECTION LINE DATA
0 / END OF MULTI-SECTION LINE DATA, BEGIN ZONE DATA
0 / END OF ZONE DATA, BEGIN INTER-AREA TRANSFER DATA
0 / END OF INTER-AREA TRANSFER DATA, BEGIN OWNER DATA
0 / END OF OWNER DATA, BEGIN FACTS DEVICE DATA
0 / END OF FACTS DEVICE DATA, BEGIN SWITCHED SHUNT DATA
0 / END OF SWITCHED SHUNT DATA, BEGIN GNE DATA
0 / END OF GNE DATA, BEGIN INDUCTION MACHINE DATA
0 / END OF INDUCTION MACHINE DATA


/Notes:
/       End of Data

ECHO
@END
```

PSS/E code for adding W.Canon – W.Station 115kV

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RDCH
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0 / END OF BUS DATA, BEGIN LOAD DATA
0 / END OF LOAD DATA, BEGING FIXED BUS SHUNT DATA
0 / END OF FIXED BUS SHUNT DATA, BEGIN GENERATOR DATA
0 / END OF GENERATOR DATA, BEGIN BRANCH DATA
70550,70456,'1', 0.024613, 0.249682, 0.0306421, 279.0, 279.0, 279.0, 0.0, 0.0, 0.0, 0.0, 1, 1, 42, 65, 1.00 /W.Canon - W.Station 115kV
0 / END OF BRANCH DATA, BEGIN TRANSFORMER DATA
0 / END OF TRANSFORMER DATA, BEGIN AREA DATA
0 / END OF AREA DATA, BEGIN TWO-TERMINAL DC DATA
0 / END OF TWO-TERMINAL DC DATA, BEGIN VSC DC LINE DATA
0 / END OF VSC DC LINE DATA, BEGIN IMPEDANCE CORRECTION DATA
0 / END OF IMPEDANCE CORRECTION DATA, BEGIN MULTI-TERMINAL DC DATA
0 / END OF MULTI-TERMINAL DC DATA, BEGIN MULTI-SECTION LINE DATA
0 / END OF MULTI-SECTION LINE DATA, BEGIN ZONE DATA
0 / END OF ZONE DATA, BEGIN INTER-AREA TRANSFER DATA
0 / END OF INTER-AREA TRANSFER DATA, BEGIN OWNER DATA
0 / END OF OWNER DATA, BEGIN FACTS DEVICE DATA
0 / END OF FACTS DEVICE DATA, BEGIN SWITCHED SHUNT DATA
0 / END OF SWITCHED SHUNT DATA, BEGIN GNE DATA
0 / END OF GNE DATA, BEGIN INDUCTION MACHINE DATA
0 / END OF INDUCTION MACHINE DATA


/Notes:
/       End of Data

ECHO
@END
```

APPENDIX E: Benchmark Cases Generation Tables

2026 Heavy Summer Generation Table

Bus Number	Bus Name	Id	Area Num	Area Name	Zone Num	In Service	PGen (MW)	PMax (MW)	PMin (MW)
1	SLVGEN 13.200	1	70	PSCOLORADO	710	1	320	1000	0
70069	CABCRKA 13.800	HA	70	PSCOLORADO	705	1	80	162	-4
70070	CABCRKB 13.800	HB	70	PSCOLORADO	705	1	80	162	-4
70104	CHEROK2 15.500	SC	70	PSCOLORADO	700	1	0	0	0
70106	CHEROK4 22.000	G4	70	PSCOLORADO	700	1	365	383	150
70119	COMAN_1 24.000	C1	70	PSCOLORADO	704	1	350	360	200
70120	COMAN_2 24.000	C2	70	PSCOLORADO	704	1	19.0174	365	200
70145	CHEROKEE5 18.000	G5	70	PSCOLORADO	700	1	150	224	0
70146	CHEROKEE6 18.000	G6	70	PSCOLORADO	700	1	150	224	0
70147	CHEROKEE7 18.000	G7	70	PSCOLORADO	700	1	220	224	0
70180	FRUITA 13.800	G1	70	PSCOLORADO	708	1	15	17	5
70188	FTLUP1-2 13.800	G1	70	PSCOLORADO	706	0	50	50	10
70188	FTLUP1-2 13.800	G2	70	PSCOLORADO	706	0	50	50	10
70310	PAWNEE 22.000	C1	70	PSCOLORADO	706	0	505	530	300
70314	MANCHEF1 16.000	G1	70	PSCOLORADO	706	1	140	140	45
70315	MANCHEF2 16.000	G2	70	PSCOLORADO	706	1	140	140	45
70334	PUB_DSLS 4.1600	G1	70	PSCOLORADO	712	1	10	25	0
70344	R.F.DSLS 4.1600	G1	70	PSCOLORADO	712	1	10	10	0
70350	RAWHIDE 24.000	C1	70	PSCOLORADO	706	1	300	304	45
70351	RAWHIDEA 13.800	GA	70	PSCOLORADO	706	1	50	70	40
70385	SHOSHA&B 4.0000	H1	70	PSCOLORADO	708	1	7	7	5
70385	SHOSHA&B 4.0000	H2	70	PSCOLORADO	708	1	7	8	5
70406	ST.VR_2 18.000	G2	70	PSCOLORADO	706	1	100	130	45
70407	ST.VR_3 18.000	G3	70	PSCOLORADO	706	1	100	130	45
70408	ST.VR_4 18.000	G4	70	PSCOLORADO	706	1	100	130	45

70409	ST.VRAIN 22.000	G1	70	PSCOLORADO	706	1	320	342	35
70485	ALMSACT1 13.800	G1	70	PSCOLORADO	710	0	16	17	5
70486	ALMSACT2 13.800	G2	70	PSCOLORADO	710	0	18	19	5
70487	JMSHAFR4 13.800	G4	70	PSCOLORADO	706	1	34.8	34.4	23
70487	JMSHAFR4 13.800	G5	70	PSCOLORADO	706	1	33	33.4	23
70490	JMSHAFR3 13.800	G3	70	PSCOLORADO	706	1	36.1	35.4	22
70490	JMSHAFR3 13.800	ST	70	PSCOLORADO	706	1	50	50.7	24
70493	JMSHAFR2 13.800	ST	70	PSCOLORADO	706	1	50.7	50.7	24
70495	JMSHAFR1 13.800	G1	70	PSCOLORADO	706	1	35.8	35.4	23
70495	JMSHAFR1 13.800	G2	70	PSCOLORADO	706	1	35	35.4	23
70498	QF_BCP2T 13.800	G3	70	PSCOLORADO	706	1	31.1	30.4	17
70498	QF_BCP2T 13.800	ST	70	PSCOLORADO	706	1	36	36.7	17
70499	QF_B4-4T 13.800	G4	70	PSCOLORADO	706	1	24	24	7
70499	QF_B4-4T 13.800	G5	70	PSCOLORADO	706	1	23	24	7
70500	QF_CPP1T 13.800	G1	70	PSCOLORADO	706	1	23	24	10
70500	QF_CPP1T 13.800	G2	70	PSCOLORADO	706	1	23	24	10
70501	QF_CPP3T 13.800	ST	70	PSCOLORADO	706	1	26	27	10
70548	APT_DSLS 4.1600	G1	70	PSCOLORADO	712	1	10	10	0
70553	ARAP5&6 13.800	G5	70	PSCOLORADO	700	1	36	37	17
70553	ARAP5&6 13.800	G6	70	PSCOLORADO	700	1	36	37	17
70554	ARAP7 13.800	G7	70	PSCOLORADO	700	1	44	45	17
70556	QF_B4D4T 12.500	ST	70	PSCOLORADO	706	1	50	70	17
70557	VALMNT7 13.800	G7	70	PSCOLORADO	703	1	36	37	17
70558	VALMNT8 13.800	G8	70	PSCOLORADO	703	1	36	37	17
70560	LAMAR_DC 230.00	DC	70	PSCOLORADO	712	0	101	210	-210
70561	RAWHIDEF 18.000	GF	70	PSCOLORADO	706	1	125	138	50
70562	SPRUCE1 18.000	G1	70	PSCOLORADO	700	1	100	140	50
70563	SPRUCE2 18.000	G2	70	PSCOLORADO	700	1	100	140	50
70564	RAWHIDE_PV 34.500	PV	70	PSCOLORADO	706	1	7	32.7	0
70565	KNUTSON1 13.800	G1	70	PSCOLORADO	700	1	51.8	64.5	40
70566	KNUTSON2 13.800	G2	70	PSCOLORADO	700	1	51.9	64.5	40

70567	RAWHIDED 13.800	GD	70	PSCOLORADO	706	1	50	70	40
70568	RAWHIDEB 13.800	GB	70	PSCOLORADO	706	1	50	70	40
70569	RAWHIDEC 13.800	GC	70	PSCOLORADO	706	1	50	70	40
70577	FTNVL1&2 13.800	G1	70	PSCOLORADO	704	0	0	40	17
70577	FTNVL1&2 13.800	G2	70	PSCOLORADO	704	0	0	40	17
70578	FTNVL3&4 13.800	G3	70	PSCOLORADO	704	0	0	40	17
70578	FTNVL3&4 13.800	G4	70	PSCOLORADO	704	0	0	40	17
70579	FTNVL5&6 13.800	G5	70	PSCOLORADO	704	0	0	40	17
70579	FTNVL5&6 13.800	G6	70	PSCOLORADO	704	0	0	40	17
70580	PLNENDG1 13.800	G0	70	PSCOLORADO	700	1	4.8	5.5	1.7
70580	PLNENDG1 13.800	G1	70	PSCOLORADO	700	1	4.8	5.5	1.7
70580	PLNENDG1 13.800	G2	70	PSCOLORADO	700	1	4.8	5.5	1.7
70580	PLNENDG1 13.800	G3	70	PSCOLORADO	700	1	4.8	5.5	1.7
70580	PLNENDG1 13.800	G4	70	PSCOLORADO	700	1	4.8	5.5	1.7
70580	PLNENDG1 13.800	G5	70	PSCOLORADO	700	1	4.8	5.5	1.7
70580	PLNENDG1 13.800	G6	70	PSCOLORADO	700	1	4.8	5.5	1.7
70580	PLNENDG1 13.800	G7	70	PSCOLORADO	700	1	4.8	5.5	1.7
70580	PLNENDG1 13.800	G8	70	PSCOLORADO	700	1	4.8	5.5	1.7
70580	PLNENDG1 13.800	G9	70	PSCOLORADO	700	1	4.8	5.5	1.7
70585	PLNENDG3 13.800	G1	70	PSCOLORADO	700	1	7.2	8.4	0
70585	PLNENDG3 13.800	G2	70	PSCOLORADO	700	1	7.2	8.4	0
70585	PLNENDG3 13.800	G3	70	PSCOLORADO	700	1	7.2	8.4	0
70585	PLNENDG3 13.800	G4	70	PSCOLORADO	700	1	7.2	8.4	0
70585	PLNENDG3 13.800	G5	70	PSCOLORADO	700	1	7.2	8.4	0
70585	PLNENDG3 13.800	G6	70	PSCOLORADO	700	1	7.2	8.4	0
70585	PLNENDG3 13.800	G7	70	PSCOLORADO	700	1	7.2	8.4	0
70586	PLNENDG4 13.800	G1	70	PSCOLORADO	700	1	7.2	8.4	0
70586	PLNENDG4 13.800	G2	70	PSCOLORADO	700	1	7.2	8.4	0
70586	PLNENDG4 13.800	G3	70	PSCOLORADO	700	1	7.2	8.4	0
70586	PLNENDG4 13.800	G4	70	PSCOLORADO	700	1	7.2	8.4	0
70586	PLNENDG4 13.800	G5	70	PSCOLORADO	700	1	7.2	8.4	0

70586	PLNENDG4 13.800	G6	70	PSCOLORADO	700	1	7.2	8.4	0
70586	PLNENDG4 13.800	G7	70	PSCOLORADO	700	1	7.2	8.4	0
70587	PLNENDG2 13.800	G0	70	PSCOLORADO	700	1	4.8	5.5	1.7
70587	PLNENDG2 13.800	G1	70	PSCOLORADO	700	1	4.8	5.5	1.7
70587	PLNENDG2 13.800	G2	70	PSCOLORADO	700	1	4.8	5.5	1.7
70587	PLNENDG2 13.800	G3	70	PSCOLORADO	700	1	4.8	5.5	1.7
70587	PLNENDG2 13.800	G4	70	PSCOLORADO	700	1	4.8	5.5	1.7
70587	PLNENDG2 13.800	G5	70	PSCOLORADO	700	1	4.8	5.5	1.7
70587	PLNENDG2 13.800	G6	70	PSCOLORADO	700	1	4.8	5.5	1.7
70587	PLNENDG2 13.800	G7	70	PSCOLORADO	700	1	4.8	5.5	1.7
70587	PLNENDG2 13.800	G8	70	PSCOLORADO	700	1	4.8	5.5	1.7
70587	PLNENDG2 13.800	G9	70	PSCOLORADO	700	1	4.8	5.5	1.7
70588	RMEC1 15.000	G1	70	PSCOLORADO	700	1	100	150	5
70589	RMEC2 15.000	G2	70	PSCOLORADO	700	1	100	150	6
70591	RMEC3 23.000	G3	70	PSCOLORADO	700	1	322	322	17
70593	SPNDLE1 18.000	G1	70	PSCOLORADO	703	1	100	134	0
70594	SPNDLE2 18.000	G2	70	PSCOLORADO	703	1	100	134	0
70622	MIS_SITE 34.500	W1	70	PSCOLORADO	700	1	52.5	250	0
70635	LIMON1_W 34.500	W1	70	PSCOLORADO	700	1	42.2	201	0
70636	LIMON2_W 34.500	W2	70	PSCOLORADO	700	1	42.2	201	0
70637	LIMON3_W 34.500	W3	70	PSCOLORADO	700	1	42.2	201	0
70665	JKFUL_W1 0.6900	W1	70	PSCOLORADO	757	1	26.06	124.1	0
70666	JKFUL_W2 0.6900	W2	70	PSCOLORADO	757	1	26.42	125.8	0
70701	CO_GRN_E 34.500	W1	70	PSCOLORADO	712	1	17	81	10
70702	CO_GRN_W 34.500	W2	70	PSCOLORADO	712	1	17	81	10
70703	TWNBUTTE 34.500	W1	70	PSCOLORADO	712	1	15.8	75	0
70710	PTZLOGN1 34.500	W1	70	PSCOLORADO	706	1	42.2	201	0
70712	PTZLOGN2 34.500	W2	70	PSCOLORADO	706	1	25.2	120	0
70713	PTZLOGN3 34.500	W3	70	PSCOLORADO	706	1	16.7	79.5	0
70714	PTZLOGN4 34.500	W4	70	PSCOLORADO	706	1	36.8	175	0
70721	SPRNGCAN 34.500	W1	70	PSCOLORADO	706	1	12.6	60	0

70723	RDGCREST 34.500	W1	70	PSCOLORADO	752	1	6.3	29.7	0
70724	SPRINGCAN 34.500	W1	70	PSCOLORADO	706	1	12.6	60	0
70777	COMAN_3 27.000	C3	70	PSCOLORADO	704	1	805	805	200
70823	CEDARCK_1A 34.500	W2	70	PSCOLORADO	706	1	46.2	220	0
70824	CEDARCK_1B 34.500	W3	70	PSCOLORADO	706	1	16.8	80	0
70825	CEDARCK_2A 34.500	W1	70	PSCOLORADO	706	1	31.5	150	0
70826	CEDARCK_2B 34.500	W2	70	PSCOLORADO	706	1	21.5	100	0
70931	G-SANDHIL_PV34.500	S1	70	PSCOLORADO	710	1	10.4	16	0
70932	SOLAR_GE 34.500	S2	70	PSCOLORADO	710	1	19.5	30	0
70933	COGENTRIX_PV34.500	S3	70	PSCOLORADO	710	1	19.5	30	0
70934	COMAN_PV 34.500	S1	70	PSCOLORADO	704	1	78	120	0
70935	SUNPOWER 34.500	S1	70	PSCOLORADO	710	1	28.6	52	0
70950	ST.VR_5 18.000	G5	70	PSCOLORADO	706	1	100	150	35
70951	ST.VR_6 18.000	G6	70	PSCOLORADO	706	1	100	150	35
70953	PAWNCT_PLAN 22.000	C2	70	PSCOLORADO	706	1	500	530	300
71001	BAC_MSA GEN113.800	G1	70	PSCOLORADO	712	1	90	90.6	0
71002	BAC_MSA GEN213.800	G1	70	PSCOLORADO	712	1	90	90.6	0
71003	BAC_MSA GEN313.800	G1	70	PSCOLORADO	712	1	40	40	0
71003	BAC_MSA GEN313.800	G2	70	PSCOLORADO	712	1	40	40	0
71003	BAC_MSA GEN313.800	S1	70	PSCOLORADO	712	1	24	24.8	0
71004	BAC_MSA GEN413.800	G1	70	PSCOLORADO	712	1	40	40	0
71004	BAC_MSA GEN413.800	G2	70	PSCOLORADO	712	1	40	40	0
71004	BAC_MSA GEN413.800	S1	70	PSCOLORADO	712	1	24	24.8	0
71005	BAC_MSA	G1	70	PSCOLORADO	712	1	40	40	0

	GEN513.800								
71009	BUSCHRWTG1 0.7000	G1	70	PSCOLORADO	712	1	6	28.8	0
71012	BUSCHRWTG2 0.6900	G2	70	PSCOLORADO	712	1	6	28.8	0
71015	BUSCHRWTG3 0.6900	G3	70	PSCOLORADO	712	1	6	28.8	0
71016	RTLSNKWNDLO 0.7000	G1	70	PSCOLORADO	712	1	13	60	0
72000	TBII_GEN 0.6900	W	70	PSCOLORADO	712	1	17.2	76	11.4
72013	SI_GEN 0.6000	1	70	PSCOLORADO	704	1	10.3	30.2	0
72500	SPR GEN3 21.000	1	73	WAPA R.M.	790	1	452	452	165
72501	TSGT_G1 18.000	G1	73	WAPA R.M.	752	1	120	120	50
72502	TSGT_G2 18.000	G2	73	WAPA R.M.	752	1	55.88	120	50
72503	TSGT_G3 18.000	G3	73	WAPA R.M.	752	1	64.5	120	50
72514	TSGT_G4 18.000	G4	73	WAPA R.M.	752	1	64.5	120	50
72515	TSGT_G5 18.000	G5	73	WAPA R.M.	752	0	0	120	50
72703	CRSL_GEN 0.7000	W	73	WAPA R.M.	752	1	30.6	149.6	0
72714	KC_GEN 0.6900	G1	73	WAPA R.M.	752	1	12.2	51.2	2.4
72742	RIDGEWAY 4.2000	1	73	WAPA R.M.	791	1	7	7.2	0
72742	RIDGEWAY 4.2000	2	73	WAPA R.M.	791	1	0.8	0.8	0
73054	ELBERT-1 11.500	1	73	WAPA R.M.	755	1	80	105.26	0
73129	MBPP-1 24.000	1	73	WAPA R.M.	753	1	268.4689	605	0
73130	MBPP-2 24.000	1	73	WAPA R.M.	753	1	375	605	0
73181	SIDNEYDC 230.00	1	73	WAPA R.M.	756	1	196	200	-200
73226	YELLO1-2 13.800	1	73	WAPA R.M.	750	1	50	65.789	0
73226	YELLO1-2 13.800	2	73	WAPA R.M.	750	1	50	65.789	0
73227	YELLO3-4 13.800	3	73	WAPA R.M.	750	1	50	65.789	0
73227	YELLO3-4 13.800	4	73	WAPA R.M.	750	1	50	65.789	0
73289	RCCT1 13.800	1	73	WAPA R.M.	751	1	17	17	0
73291	RCCT2 13.800	2	73	WAPA R.M.	751	1	17	17	0
73292	RCCT3 13.800	3	73	WAPA R.M.	751	1	17	17	0
73293	RCCT4 13.800	4	73	WAPA R.M.	751	1	17	17	0
73299	BIGTHOMP 4.2000	1	73	WAPA R.M.	754	1	3	4.5	0

73302	BRLNGTN1 13.800	1	73	WAPA R.M.	752	1	50.4	50.4	25
73303	BRLNGTN2 13.800	1	73	WAPA R.M.	752	1	50.4	50.4	25
73306	ESTES1 6.9000	1	73	WAPA R.M.	754	1	12	19.167	0
73307	ESTES2 6.9000	1	73	WAPA R.M.	754	1	12	19.167	0
73308	ESTES3 6.9000	1	73	WAPA R.M.	754	1	12	19.167	0
73316	GREENMT1 6.9000	1	73	WAPA R.M.	755	1	10	14.444	0
73317	GREENMT2 6.9000	1	73	WAPA R.M.	755	1	10	14.444	0
73319	MARYLKPP 6.9000	1	73	WAPA R.M.	754	1	7	10.35	0
73324	POLEHILL 13.800	1	73	WAPA R.M.	754	1	35	40.25	0
73328	WILLMFRK 2.4000	1	73	WAPA R.M.	755	1	2	3	0
73332	ALCOVA1 6.9000	1	73	WAPA R.M.	753	1	15	21.8	0
73333	BOYSEN1 4.2000	1	73	WAPA R.M.	750	1	5	7.5	0
73333	BOYSEN1 4.2000	2	73	WAPA R.M.	750	1	5	7.5	0
73334	BBILL1-2 6.9000	1	73	WAPA R.M.	750	1	4	6.67	0
73334	BBILL1-2 6.9000	2	73	WAPA R.M.	750	1	4	6.67	0
73339	HEART MT 2.4000	1	73	WAPA R.M.	750	1	3	6.9	0
73341	NSS2 13.800	2	73	WAPA R.M.	751	1	93	93.7	0
73347	SHOSHONE 6.9000	1	73	WAPA R.M.	750	1	1	3.33	0
73349	FREMONT1 11.500	1	73	WAPA R.M.	753	1	27	35.16	0
73350	FREMONT2 11.500	1	73	WAPA R.M.	753	1	27	35.16	0
73351	GLENDO1 6.9000	1	73	WAPA R.M.	753	1	15	19	0
73352	GLENDO2 6.9000	1	73	WAPA R.M.	753	1	15	19	0
73353	GUERNSY1 2.4000	1	73	WAPA R.M.	753	1	2	3.2	0
73356	KORTES1 6.9000	1	73	WAPA R.M.	753	1	10	13.3	0
73357	KORTES2 6.9000	1	73	WAPA R.M.	753	1	10	13.3	0
73358	KORTES3 6.9000	1	73	WAPA R.M.	753	1	10	13.3	0
73363	SEMINOE1-2 6.9000	1	73	WAPA R.M.	753	1	12	15	0
73363	SEMINOE1-2 6.9000	2	73	WAPA R.M.	753	1	12	15	0
73381	BIRDSAL1 13.800	1	73	WAPA R.M.	757	0	0	17.2	2.9
73382	BIRDSAL2 13.800	1	73	WAPA R.M.	757	0	0	17.2	2.9
73383	BIRDSAL3 13.800	1	73	WAPA R.M.	757	0	0	24.6	3.3

73418	RD_NIXON 20.000	1	73	WAPA R.M.	757	1	220.47	225.39	110.9
73424	TESLA1 13.800	1	73	WAPA R.M.	757	1	13.2	27.5	0.9
73427	DRAKE 5 13.800	1	73	WAPA R.M.	757	0	0	49.65	26.2
73428	DRAKE 6 13.800	1	73	WAPA R.M.	757	1	80.6	83.19	42.3
73429	DRAKE 7 13.800	1	73	WAPA R.M.	757	1	137.1	141.03	74.6
73434	NIXONCT1 12.500	1	73	WAPA R.M.	757	0	0	27	19.8
73435	NIXONCT2 12.500	1	73	WAPA R.M.	757	0	0	27	19.8
73438	ALCOVA2 6.9000	1	73	WAPA R.M.	753	1	13	21.8	0
73439	BBILL3-4 6.9000	1	73	WAPA R.M.	750	1	4	6.67	0
73441	SEMINOE3 6.9000	1	73	WAPA R.M.	753	1	10	15	0
73444	GUERNSY2 2.4000	2	73	WAPA R.M.	753	1	2	3.2	0
73448	FLATIRN1 13.800	2	73	WAPA R.M.	754	1	35	47.8	0
73449	FLATIRN2 13.800	1	73	WAPA R.M.	754	1	35	47.8	0
73449	FLATIRN2 13.800	3	73	WAPA R.M.	754	1	6	8.5	-10.16
73461	ELBERT-2 11.500	1	73	WAPA R.M.	755	1	80	105.26	0
73462	SPIRTMTN 6.9000	1	73	WAPA R.M.	750	1	3	5	0
73507	FTRNG1CC 18.000	1	73	WAPA R.M.	757	1	137.3	142	71
73508	FTRNG2CC 18.000	1	73	WAPA R.M.	757	1	136.9	142	71.6
73509	FTRNG3CC 21.000	1	73	WAPA R.M.	757	1	176.19	207	39.2
73532	LINCOLN1 13.800	1	73	WAPA R.M.	752	1	64.5	64.5	40
73533	LINCOLN2 13.800	1	73	WAPA R.M.	752	1	64.5	64.5	40
73631	COHIWND_G1 0.6900	W	73	WAPA R.M.	752	1	13.1	67	12.3
73635	COHIWND_G2 0.6900	W	73	WAPA R.M.	752	1	5.1	23.1	0
74014	NSS_CT1 13.800	1	73	WAPA R.M.	751	1	40	40	0
74015	NSS_CT2 13.800	1	73	WAPA R.M.	751	1	40	40	0
74016	WYGEN 13.800	1	73	WAPA R.M.	751	1	93	93.7	0
74017	WYGEN2 13.800	1	73	WAPA R.M.	751	1	100	100	0
74018	WYGEN3 13.800	1	73	WAPA R.M.	751	1	110	110	0
74029	LNG_CT1 13.800	1	73	WAPA R.M.	751	1	40	40	0
74042	CLR_1 0.6000	1	73	WAPA R.M.	753	1	29	29.4	0
74043	SS_GEN1 0.6000	1	73	WAPA R.M.	753	1	42	42	0

74061	CPGSTN_1 13.800	G1	73	WAPA R.M.	753	1	40	40	0
74061	CPGSTN_1 13.800	G2	73	WAPA R.M.	753	1	40	40	0
74061	CPGSTN_1 13.800	S1	73	WAPA R.M.	753	1	24	24.8	0
74062	CPGSTN_2 13.800	G1	73	WAPA R.M.	753	1	40	40	0
74063	CPGSTN_3 13.800	G1	73	WAPA R.M.	753	1	40	40	0
74063	CPGSTN_3 13.800	G2	73	WAPA R.M.	753	1	40	40	0
74063	CPGSTN_3 13.800	S1	73	WAPA R.M.	753	1	20	24.8	0
76301	ARVADA1 13.800	1	73	WAPA R.M.	751	0	0	7.2	0
76302	ARVADA2 13.800	1	73	WAPA R.M.	751	0	0	7.2	0
76303	ARVADA3 13.800	1	73	WAPA R.M.	751	0	0	7.2	0
76305	BARBERC1 13.800	1	73	WAPA R.M.	751	0	0	7.2	0
76306	BARBERC2 13.800	1	73	WAPA R.M.	751	0	0	7.2	0
76307	BARBERC3 13.800	1	73	WAPA R.M.	751	0	0	7.2	0
76309	HARTZOG1 13.800	1	73	WAPA R.M.	751	0	0	7.2	0
76310	HARTZOG2 13.800	1	73	WAPA R.M.	751	0	0	7.2	0
76311	HARTZOG3 13.800	1	73	WAPA R.M.	751	0	0	7.2	0
76313	TK DVAR1 0.4800	1	73	WAPA R.M.	751	0	0	0.5	0
76314	TK DVAR2 0.4800	1	73	WAPA R.M.	751	0	0	0.5	0
76351	RCDC W 230.00	1	73	WAPA R.M.	751	1	34	200	0
76404	DRYFORK 19.000	1	73	WAPA R.M.	751	1	420	440	0
79015	CRAIG 1 22.000	1	73	WAPA R.M.	790	1	375	470	0
79016	CRAIG 2 22.000	1	73	WAPA R.M.	790	1	375	470	0
79017	CRAIG 3 22.000	1	73	WAPA R.M.	790	1	478	478	120
79019	MORRO1-2 12.500	1	73	WAPA R.M.	790	1	70	81	0
79019	MORRO1-2 12.500	2	73	WAPA R.M.	790	1	70	81	0
79040	HAYDEN1 18.000	1	73	WAPA R.M.	790	1	150	212	0
79041	HAYDEN2 22.000	1	73	WAPA R.M.	790	1	200	286	0
79123	FONTNLLE 4.1600	1	73	WAPA R.M.	790	1	7	11.111	0
79154	FLGORG1 11.500	1	73	WAPA R.M.	790	1	40	56.1	0
79155	FLGORG2 11.500	1	73	WAPA R.M.	790	1	40	56.1	0
79156	FLGORG3 11.500	1	73	WAPA R.M.	790	1	40	56.1	0

79157	BMESA1-2 11.500	1	73	WAPA R.M.	790	1	37	44	0
79157	BMESA1-2 11.500	2	73	WAPA R.M.	790	1	37	44	0
79158	NUCLA 1 13.800	1	73	WAPA R.M.	790	0	0	12	8
79159	NUCLA 2 13.800	1	73	WAPA R.M.	790	0	0	12	8
79160	NUCLA 3 13.800	1	73	WAPA R.M.	790	0	0	12	8
79161	NUCLA 4 13.800	1	73	WAPA R.M.	790	0	0	74	46
79162	CRYSTAL 11.500	1	73	WAPA R.M.	790	1	30	35	0
79164	TOWAOC 6.9000	1	73	WAPA R.M.	790	1	8	12.1	0
79166	MOLINA-L 4.2000	1	73	WAPA R.M.	790	1	3	4.9	0
79172	MOLINA-U 4.2000	1	73	WAPA R.M.	790	1	7	8.6	0
79176	MCPHEE 2.4000	1	73	WAPA R.M.	790	1	1	1.3	0
79251	QFATLAS1 13.800	1	73	WAPA R.M.	790	0	0	32.7	15
79251	QFATLAS1 13.800	2	73	WAPA R.M.	790	0	0	15.4	3
79252	QFATLAS2 13.800	3	73	WAPA R.M.	790	0	0	15.4	3
79252	QFATLAS2 13.800	4	73	WAPA R.M.	790	0	0	15.4	3

2026 Light Spring Generation Table

Bus Number	Bus Name	Id	Area Num	Area Name	Zone Num	In Service	PGen (MW)	PMax (MW)	PMin (MW)
1	SLVGEN 13.200	1	70	PSCOLORADO	710	1	0	1000	0
70069	CABCRKA 13.800	HA	70	PSCOLORADO	705	0	80	162	75
70070	CABCRKB 13.800	HB	70	PSCOLORADO	705	0	80	162	75
70083	CANON_55 13.800	C1	70	PSCOLORADO	712	0	0	18	0
70084	CANON_59 13.800	C1	70	PSCOLORADO	712	0	0	24	0
70104	CHEROK2 15.500	SC	70	PSCOLORADO	700	1	0	0	0
70106	CHEROK4 22.000	C4	70	PSCOLORADO	700	1	225	383	215
70119	COMAN_1 24.000	C1	70	PSCOLORADO	704	0	250	360	200
70120	COMAN_2 24.000	C2	70	PSCOLORADO	704	1	275.1056	365	200
70133	CTY_LAM 13.800	G1	70	PSCOLORADO	712	0	24.8	27	10
70135	CTY LAM 13.800	G2	70	PSCOLORADO	712	0	16.9	17	8

70145	CHEROK5 18.000	G5	70	PSCOLORADO	700	1	100	168	70
70146	CHEROK6 18.000	G6	70	PSCOLORADO	700	1	100	168	70
70147	CHEROK7 18.000	G7	70	PSCOLORADO	700	1	175	240	70
70160	E_CANON 69.000	G1	70	PSCOLORADO	712	0	0	8	0
70180	FRUITA 13.800	G1	70	PSCOLORADO	708	0	15	17	5
70306	PP_MINE 69.000	G1	70	PSCOLORADO	712	0	0	3	0
70310	PAWNEE 22.000	C1	70	PSCOLORADO	706	1	325	536	305
70314	MANCHEF1 16.000	G1	70	PSCOLORADO	706	0	130	140	45
70315	MANCHEF2 16.000	G2	70	PSCOLORADO	706	0	130	140	45
70334	PUB_DSLS 4.1600	G1	70	PSCOLORADO	712	0	0	25	0
70337	PUEBPLNT 14.000	G1	70	PSCOLORADO	712	0	0	20	5
70337	PUEBPLNT 14.000	G2	70	PSCOLORADO	712	0	0	9	0
70344	R.F.DSLS 4.1600	G1	70	PSCOLORADO	712	0	0	10	0
70350	RAWHIDE 24.000	C1	70	PSCOLORADO	706	1	283	304	45
70351	RAWHIDEA 13.800	GA	70	PSCOLORADO	706	0	65	70	40
70385	SHOSHA&B 4.0000	H1	70	PSCOLORADO	708	1	7	7	5
70385	SHOSHA&B 4.0000	H2	70	PSCOLORADO	708	1	8	8	5
70406	ST.VR_2 18.000	G2	70	PSCOLORADO	706	1	65	127	65
70407	ST.VR_3 18.000	G3	70	PSCOLORADO	706	1	65	132	65
70408	ST.VR_4 18.000	G4	70	PSCOLORADO	706	1	65	132	65
70409	ST.VRAIN 22.000	G1	70	PSCOLORADO	706	0	150	309	39
70487	JMSHAFR4 13.800	G4	70	PSCOLORADO	706	0	0	34.4	23
70487	JMSHAFR4 13.800	G5	70	PSCOLORADO	706	0	0	33.4	23
70490	JMSHAFR3 13.800	G3	70	PSCOLORADO	706	0	0	35.4	22
70490	JMSHAFR3 13.800	ST	70	PSCOLORADO	706	0	0	50.7	24
70493	JMSHAFR2 13.800	ST	70	PSCOLORADO	706	0	0	50.7	24
70495	JMSHAFR1 13.800	G1	70	PSCOLORADO	706	0	0	35.4	23
70495	JMSHAFR1 13.800	G2	70	PSCOLORADO	706	0	0	35.4	23
70498	QF_BCP2T 13.800	G3	70	PSCOLORADO	706	0	0	30.4	17
70498	QF_BCP2T 13.800	ST	70	PSCOLORADO	706	0	0	36.7	17
70499	QF_B4-4T 13.800	G4	70	PSCOLORADO	706	0	24	24	7

70499	QF_B4-4T 13.800	G5	70	PSCOLORADO	706	0	23	24	7
70500	QF_CPP1T 13.800	G1	70	PSCOLORADO	706	0	23	24	10
70500	QF_CPP1T 13.800	G2	70	PSCOLORADO	706	0	23	24	10
70501	QF_CPP3T 13.800	ST	70	PSCOLORADO	706	0	26	27	10
70503	PONNEQUI 26.100	W1	70	PSCOLORADO	754	1	5.7	30	0
70548	APT_DSLS 4.1600	G1	70	PSCOLORADO	712	0	0	10	0
70553	ARAP5&6 13.800	G5	70	PSCOLORADO	700	0	36	37	17
70553	ARAP5&6 13.800	G6	70	PSCOLORADO	700	0	36	37	17
70554	ARAP7 13.800	G7	70	PSCOLORADO	700	0	44	45	17
70556	QF_B4D4T 12.500	ST	70	PSCOLORADO	706	0	50	70	17
70557	VALMNT7 13.800	G7	70	PSCOLORADO	703	0	36	37	17
70558	VALMNT8 13.800	G8	70	PSCOLORADO	703	0	36	37	17
70560	LAMAR_DC 230.00	DC	70	PSCOLORADO	712	1	0	210	-210
70561	RAWHIDEF 18.000	GF	70	PSCOLORADO	706	0	128	138	50
70562	SPRUCE1 18.000	G1	70	PSCOLORADO	700	0	130	132	70
70563	SPRUCE2 18.000	G2	70	PSCOLORADO	700	0	130	136	69
70565	KNUTSON1 13.800	G1	70	PSCOLORADO	700	0	0	64.5	40
70566	KNUTSON2 13.800	G2	70	PSCOLORADO	700	0	0	64.5	40
70567	RAWHIDED 13.800	GD	70	PSCOLORADO	706	0	65	70	40
70568	RAWHIDEB 13.800	GB	70	PSCOLORADO	706	0	65	70	40
70569	RAWHIDEC 13.800	GC	70	PSCOLORADO	706	0	65	70	40
70577	FTNVL1&2 13.800	G1	70	PSCOLORADO	704	0	40	40	17
70577	FTNVL1&2 13.800	G2	70	PSCOLORADO	704	0	40	40	17
70578	FTNVL3&4 13.800	G3	70	PSCOLORADO	704	0	40	40	17
70578	FTNVL3&4 13.800	G4	70	PSCOLORADO	704	0	40	40	17
70579	FTNVL5&6 13.800	G5	70	PSCOLORADO	704	0	40	40	17
70579	FTNVL5&6 13.800	G6	70	PSCOLORADO	704	0	40	40	17
70580	PLNENDG1 13.800	G0	70	PSCOLORADO	700	0	4.8	5.5	1.7
70580	PLNENDG1 13.800	G1	70	PSCOLORADO	700	0	4.8	5.5	1.7
70580	PLNENDG1 13.800	G2	70	PSCOLORADO	700	0	4.8	5.5	1.7
70580	PLNENDG1 13.800	G3	70	PSCOLORADO	700	0	4.8	5.5	1.7

70580	PLNENDG1 13.800	G4	70	PSCOLORADO	700	0	4.8	5.5	1.7
70580	PLNENDG1 13.800	G5	70	PSCOLORADO	700	0	4.8	5.5	1.7
70580	PLNENDG1 13.800	G6	70	PSCOLORADO	700	0	4.8	5.5	1.7
70580	PLNENDG1 13.800	G7	70	PSCOLORADO	700	0	4.8	5.5	1.7
70580	PLNENDG1 13.800	G8	70	PSCOLORADO	700	0	4.8	5.5	1.7
70580	PLNENDG1 13.800	G9	70	PSCOLORADO	700	0	4.8	5.5	1.7
70585	PLNENDG3 13.800	G1	70	PSCOLORADO	700	0	7.2	8.4	0
70585	PLNENDG3 13.800	G2	70	PSCOLORADO	700	0	7.2	8.4	0
70585	PLNENDG3 13.800	G3	70	PSCOLORADO	700	0	7.2	8.4	0
70585	PLNENDG3 13.800	G4	70	PSCOLORADO	700	0	7.2	8.4	0
70585	PLNENDG3 13.800	G5	70	PSCOLORADO	700	0	7.2	8.4	0
70585	PLNENDG3 13.800	G6	70	PSCOLORADO	700	0	7.2	8.4	0
70585	PLNENDG3 13.800	G7	70	PSCOLORADO	700	0	7.2	8.4	0
70586	PLNENDG4 13.800	G1	70	PSCOLORADO	700	0	7.2	8.4	0
70586	PLNENDG4 13.800	G2	70	PSCOLORADO	700	0	7.2	8.4	0
70586	PLNENDG4 13.800	G3	70	PSCOLORADO	700	0	7.2	8.4	0
70586	PLNENDG4 13.800	G4	70	PSCOLORADO	700	0	7.2	8.4	0
70586	PLNENDG4 13.800	G5	70	PSCOLORADO	700	0	7.2	8.4	0
70586	PLNENDG4 13.800	G6	70	PSCOLORADO	700	0	7.2	8.4	0
70586	PLNENDG4 13.800	G7	70	PSCOLORADO	700	0	7.2	8.4	0
70587	PLNENDG2 13.800	G0	70	PSCOLORADO	700	0	4.8	5.5	1.7
70587	PLNENDG2 13.800	G1	70	PSCOLORADO	700	0	4.8	5.5	1.7
70587	PLNENDG2 13.800	G2	70	PSCOLORADO	700	0	4.8	5.5	1.7
70587	PLNENDG2 13.800	G3	70	PSCOLORADO	700	0	4.8	5.5	1.7
70587	PLNENDG2 13.800	G4	70	PSCOLORADO	700	0	4.8	5.5	1.7
70587	PLNENDG2 13.800	G5	70	PSCOLORADO	700	0	4.8	5.5	1.7
70587	PLNENDG2 13.800	G6	70	PSCOLORADO	700	0	4.8	5.5	1.7
70587	PLNENDG2 13.800	G7	70	PSCOLORADO	700	0	4.8	5.5	1.7
70587	PLNENDG2 13.800	G8	70	PSCOLORADO	700	0	4.8	5.5	1.7
70587	PLNENDG2 13.800	G9	70	PSCOLORADO	700	0	4.8	5.5	1.7
70588	RMEC1 15.000	G1	70	PSCOLORADO	700	1	82	147	82

70589	RMEC2 15.000	G2	70	PSCOLORADO	700	1	82	147	82
70591	RMEC3 23.000	G3	70	PSCOLORADO	700	1	120	292	52
70593	SPNDLE1 18.000	G1	70	PSCOLORADO	703	0	75	134	0
70594	SPNDLE2 18.000	G2	70	PSCOLORADO	703	0	75	134	0
70622	MIS_SITE 34.500	W1	70	PSCOLORADO	700	1	75	250	0
70635	LIMON1_W 34.500	W1	70	PSCOLORADO	700	1	60.3	201	0
70636	LIMON2_W 34.500	W2	70	PSCOLORADO	700	1	60.3	201	0
70637	LIMON3_W 34.500	W3	70	PSCOLORADO	700	1	60.3	201	0
70665	JKFUL_W1 0.6900	W1	70	PSCOLORADO	757	1	37.23	124.1	0
70666	JKFUL_W2 0.6900	W2	70	PSCOLORADO	757	1	37.74	125.8	0
70701	CO_GRN_E 34.500	W1	70	PSCOLORADO	712	1	24.3	81	10
70702	CO_GRN_W 34.500	W2	70	PSCOLORADO	712	1	24.3	81	10
70703	TWNBUTTE 34.500	W1	70	PSCOLORADO	712	1	22.5	75	0
70710	PTZLOGN1 34.500	W1	70	PSCOLORADO	706	1	60.3	201	0
70712	PTZLOGN2 34.500	W2	70	PSCOLORADO	706	1	36	120	0
70713	PTZLOGN3 34.500	W3	70	PSCOLORADO	706	1	23.85	79.5	0
70714	PTZLOGN4 34.500	W4	70	PSCOLORADO	706	1	52.5	175	0
70721	SPRNGCAN 34.500	W1	70	PSCOLORADO	706	1	18	60	0
70723	RDGCREST 34.500	W1	70	PSCOLORADO	752	1	8.91	29.7	0
70777	COMAN_3 27.000	C3	70	PSCOLORADO	704	1	675	788	450
70823	CEDARCK_1A 34.500	W2	70	PSCOLORADO	706	1	66	220	0
70824	CEDARCK_1B 34.500	W3	70	PSCOLORADO	706	1	24	80	0
70825	CEDARCK_2A 34.500	W1	70	PSCOLORADO	706	1	45	150	0
70826	CEDARCK_2B 34.500	W2	70	PSCOLORADO	706	1	30	100	0
70931	G-SANDHIL_PV34.500	S1	70	PSCOLORADO	710	1	10.4	16	0
70932	IBERDROLA_PV34.500	S2	70	PSCOLORADO	710	1	19.5	30	0
70933	COGENTRIX_PV34.500	S3	70	PSCOLORADO	710	1	19.5	30	0
70934	COMAN_PV 34.500	S1	70	PSCOLORADO	704	1	0	120	0
70935	SUNPOWER 34.500	S1	70	PSCOLORADO	710	1	33.8	52	0
70950	ST.VR_5 18.000	G5	70	PSCOLORADO	706	1	75	148	73
70951	ST.VR_6 18.000	G6	70	PSCOLORADO	706	1	76	147	76

71001	BAC_MSA GEN113.800	G1	70	PSCOLORADO	712	1	90	90.6	0
71002	BAC_MSA GEN213.800	G1	70	PSCOLORADO	712	1	90	90.6	0
71003	BAC_MSA GEN313.800	G1	70	PSCOLORADO	712	1	12	40	0
71003	BAC_MSA GEN313.800	G2	70	PSCOLORADO	712	0	0	40	0
71003	BAC_MSA GEN313.800	S1	70	PSCOLORADO	712	0	0	24.8	0
71004	BAC_MSA GEN413.800	G1	70	PSCOLORADO	712	0	0	40	0
71004	BAC_MSA GEN413.800	G2	70	PSCOLORADO	712	0	0	40	0
71004	BAC_MSA GEN413.800	S1	70	PSCOLORADO	712	0	0	24.8	0
71005	BAC_MSA GEN513.800	G1	70	PSCOLORADO	712	0	0	40	0
71009	BUSCHRWTG1 0.7000	G1	70	PSCOLORADO	712	1	4	28.8	0
71012	BUSCHRWTG2 0.6900	G2	70	PSCOLORADO	712	1	4	28.8	0
71015	BUSCHRWTG3 0.6900	G3	70	PSCOLORADO	712	1	4	28.8	0
72500	SPR GEN3 21.000	1	73	WAPA R.M.	790	1	415	452	165
72714	KC_GEN 0.6900	G1	73	WAPA R.M.	752	1	15.2	51.2	2.4
72742	RIDGEWAY 4.2000	1	73	WAPA R.M.	791	0	0	7.2	0
72742	RIDGEWAY 4.2000	2	73	WAPA R.M.	791	0	0	0.8	0
73054	ELBERT-1 11.500	1	73	WAPA R.M.	755	1	45	105.26	0
73105	LAPORTE 115.00	TP	73	WAPA R.M.	754	1	1.294	1.486	0
73129	MBPP-1 24.000	1	73	WAPA R.M.	753	1	341.3211	605	0
73130	MBPP-2 24.000	1	73	WAPA R.M.	753	1	300	605	0
73181	SIDNEYDC 230.00	1	73	WAPA R.M.	756	1	196	200	-200
73226	YELLO1-2 13.800	1	73	WAPA R.M.	750	1	28	65.789	0
73226	YELLO1-2 13.800	2	73	WAPA R.M.	750	1	28	65.789	0
73227	YELLO3-4 13.800	3	73	WAPA R.M.	750	1	28	65.789	0

73227	YELLO3-4 13.800	4	73	WAPA R.M.	750	1	28	65.789	0
73289	RCCT1 13.800	1	73	WAPA R.M.	751	0	0	17	0
73291	RCCT2 13.800	2	73	WAPA R.M.	751	0	0	17	0
73292	RCCT3 13.800	3	73	WAPA R.M.	751	0	0	17	0
73293	RCCT4 13.800	4	73	WAPA R.M.	751	0	0	17	0
73299	BIGTHOMP 4.2000	1	73	WAPA R.M.	754	1	3	4.5	0
73302	BRLNGTN1 13.800	1	73	WAPA R.M.	752	0	0	50.4	25
73303	BRLNGTN2 13.800	1	73	WAPA R.M.	752	0	0	50.4	25
73306	ESTES1 6.9000	1	73	WAPA R.M.	754	1	7	19.167	0
73307	ESTES2 6.9000	1	73	WAPA R.M.	754	1	7	19.167	0
73308	ESTES3 6.9000	1	73	WAPA R.M.	754	1	7	19.167	0
73316	GREENMT1 6.9000	1	73	WAPA R.M.	755	1	6	14.444	0
73317	GREENMT2 6.9000	1	73	WAPA R.M.	755	1	6	14.444	0
73319	MARYLKPP 6.9000	1	73	WAPA R.M.	754	1	4	10.35	0
73324	POLEHILL 13.800	1	73	WAPA R.M.	754	1	17	40.25	0
73328	WILLMFRK 2.4000	1	73	WAPA R.M.	755	1	2	3	0
73332	ALCOVA1 6.9000	1	73	WAPA R.M.	753	1	9	21.8	0
73333	BOYSEN1 4.2000	1	73	WAPA R.M.	750	1	4	7.5	0
73333	BOYSEN1 4.2000	2	73	WAPA R.M.	750	1	4	7.5	0
73334	BBILL1-2 6.9000	1	73	WAPA R.M.	750	1	4	6.67	0
73334	BBILL1-2 6.9000	2	73	WAPA R.M.	750	1	4	6.67	0
73339	HEART MT 2.4000	1	73	WAPA R.M.	750	1	3	6.9	0
73341	NSS2 13.800	2	73	WAPA R.M.	751	1	93	93.7	0
73347	SHOSHONE 6.9000	1	73	WAPA R.M.	750	1	2	3.33	0
73349	FREMONT1 11.500	1	73	WAPA R.M.	753	1	15	35.16	0
73350	FREMONT2 11.500	1	73	WAPA R.M.	753	1	15	35.16	0
73351	GLENDO1 6.9000	1	73	WAPA R.M.	753	1	7	19	0
73352	GLENDO2 6.9000	1	73	WAPA R.M.	753	1	7	19	0
73353	GUERNSY1 2.4000	1	73	WAPA R.M.	753	1	2	3.2	0
73356	KORTES1 6.9000	1	73	WAPA R.M.	753	1	6	13.3	0
73357	KORTES2 6.9000	1	73	WAPA R.M.	753	1	6	13.3	0

73358	KORTES3 6.9000	1	73	WAPA R.M.	753	1	6	13.3	0
73363	SEMINOE1-2 6.9000	1	73	WAPA R.M.	753	1	6	15	0
73363	SEMINOE1-2 6.9000	2	73	WAPA R.M.	753	1	6	15	0
73381	BIRDSAL1 13.800	1	73	WAPA R.M.	757	0	0	17.2	2.9
73382	BIRDSAL2 13.800	1	73	WAPA R.M.	757	0	0	17.2	2.9
73383	BIRDSAL3 13.800	1	73	WAPA R.M.	757	0	0	24.6	3.3
73389	BRIARGATE S 115.00	TP	73	WAPA R.M.	757	1	16.2	17	0
73395	CTTNWD S 34.500	TP	73	WAPA R.M.	757	1	16.2	17	0
73396	DRAKE E 34.500	TP	73	WAPA R.M.	757	0	0	9	0
73417	RD_NIXON 115.00	TP	73	WAPA R.M.	757	0	0	12	0
73418	RD_NIXON 20.000	1	73	WAPA R.M.	757	1	212.39	225.39	110.9
73424	TESLA1 13.800	1	73	WAPA R.M.	757	1	1.2	27.5	0.9
73427	DRAKE 5 13.800	1	73	WAPA R.M.	757	1	31.65	49.6	26.2
73428	DRAKE 6 13.800	1	73	WAPA R.M.	757	1	44.19	83.19	42.3
73429	DRAKE 7 13.800	1	73	WAPA R.M.	757	1	94.343	141.03	74.6
73434	NIXONCT1 12.500	1	73	WAPA R.M.	757	0	0	27	19.8
73435	NIXONCT2 12.500	1	73	WAPA R.M.	757	0	0	27	19.8
73438	ALCOVA2 6.9000	1	73	WAPA R.M.	753	1	9	21.8	0
73439	BBILL3-4 6.9000	1	73	WAPA R.M.	750	1	4	6.67	0
73441	SEMINOE3 6.9000	1	73	WAPA R.M.	753	1	6	15	0
73444	GUERNSY2 2.4000	2	73	WAPA R.M.	753	1	2.9	3.2	0
73448	FLATIRN1 13.800	2	73	WAPA R.M.	754	1	20	47.8	0
73449	FLATIRN2 13.800	1	73	WAPA R.M.	754	1	20	47.8	0
73449	FLATIRN2 13.800	3	73	WAPA R.M.	754	1	4	8.5	-10.16
73461	ELBERT-2 11.500	1	73	WAPA R.M.	755	1	45	105.26	0
73462	SPIRTMTN 6.9000	1	73	WAPA R.M.	750	1	3	5	0
73470	COLLEGLK 230.00	TP	73	WAPA R.M.	754	1	0.813	0.934	0
73499	CROSSRDS 115.00	TP	73	WAPA R.M.	754	1	0.212	0.243	0
73507	FTRNG1CC 18.000	1	73	WAPA R.M.	757	0	0	142	71
73508	FTRNG2CC 18.000	1	73	WAPA R.M.	757	0	0	142	71.6
73509	FTRNG3CC 21.000	1	73	WAPA R.M.	757	0	0	207	39.2

73520	BFDIESEL 4.1600	1	73	WAPA R.M.	751	0	0	10	0
73532	LINCOLN1 13.800	1	73	WAPA R.M.	752	1	44	64.5	40
73533	LINCOLN2 13.800	1	73	WAPA R.M.	752	0	0	64.5	40
73564	KETTLECK 34.500	TP	73	WAPA R.M.	757	1	16.2	17	0
73565	KELKER W 34.500	TP	73	WAPA R.M.	757	0	0	1.1	0
73600	COBBLAKE 115.00	TP	73	WAPA R.M.	754	1	0.769	0.883	0
73631	COHIWND_G1 0.6900	W	73	WAPA R.M.	752	1	20.1	67.1	12.3
73635	COHIWND_G2 0.6900	W	73	WAPA R.M.	752	1	7.1	23.1	0
74014	NSS_CT1 13.800	1	73	WAPA R.M.	751	0	0	40	0
74015	NSS_CT2 13.800	1	73	WAPA R.M.	751	0	0	40	0
74016	WYGEN 13.800	1	73	WAPA R.M.	751	1	93	93.7	0
74017	WYGEN2 13.800	1	73	WAPA R.M.	751	1	100	100	0
74018	WYGEN3 13.800	1	73	WAPA R.M.	751	1	110	110	0
74029	LNG_CT1 13.800	1	73	WAPA R.M.	751	0	0	40	0
74042	CLR_1 0.6000	1	73	WAPA R.M.	753	0	7	29.4	0
74043	SS_GEN1 0.6000	1	73	WAPA R.M.	753	0	7	42	0
74061	CPGSTN_1 13.800	G1	73	WAPA R.M.	753	1	38	40	0
74061	CPGSTN_1 13.800	G2	73	WAPA R.M.	753	0	0	40	0
74061	CPGSTN_1 13.800	S1	73	WAPA R.M.	753	0	0	24.8	0
74062	CPGSTN_2 13.800	G1	73	WAPA R.M.	753	0	0	40	0
74062	CPGSTN_2 13.800	G2	73	WAPA R.M.	753	0	0	40	0
74062	CPGSTN_2 13.800	S1	73	WAPA R.M.	753	0	0	24.8	0
74063	CPGSTN_3 13.800	G1	73	WAPA R.M.	753	0	0	40	0
74399	BHPLPLAN 13.800	1	73	WAPA R.M.	751	0	0	100	0
76301	ARVADA1 13.800	1	73	WAPA R.M.	751	0	0	7.2	0
76302	ARVADA2 13.800	1	73	WAPA R.M.	751	0	0	7.2	0
76303	ARVADA3 13.800	1	73	WAPA R.M.	751	0	0	7.2	0
76305	BARBERC1 13.800	1	73	WAPA R.M.	751	0	0	7.2	0
76306	BARBERC2 13.800	1	73	WAPA R.M.	751	0	0	7.2	0
76307	BARBERC3 13.800	1	73	WAPA R.M.	751	0	0	7.2	0
76309	HARTZOG1 13.800	1	73	WAPA R.M.	751	0	0	7.2	0

76310	HARTZOG2 13.800	1	73	WAPA R.M.	751	0	0	7.2	0
76311	HARTZOG3 13.800	1	73	WAPA R.M.	751	0	0	7.2	0
76313	TK DVAR1 0.4800	1	73	WAPA R.M.	751	0	0	0.5	0
76314	TK DVAR2 0.4800	1	73	WAPA R.M.	751	0	0	0.5	0
76351	RCDC W 230.00	1	73	WAPA R.M.	751	1	-130	200	0
76404	DRYFORK 19.000	1	73	WAPA R.M.	751	0	0	0	0
76502	SPFSHPRK 69.000	1	73	WAPA R.M.	751	0	0	4	0
79015	CRAIG 1 22.000	1	73	WAPA R.M.	790	1	351	470	0
79016	CRAIG 2 22.000	1	73	WAPA R.M.	790	1	351	470	0
79017	CRAIG 3 22.000	1	73	WAPA R.M.	790	1	373.8	478	120
79019	MORRO1-2 12.500	1	73	WAPA R.M.	790	1	35	81	0
79019	MORRO1-2 12.500	2	73	WAPA R.M.	790	1	35	81	0
79040	HAYDEN1 18.000	1	73	WAPA R.M.	790	1	183	202	95
79041	HAYDEN2 22.000	1	73	WAPA R.M.	790	1	260	285	125
79123	FONTNLLE 4.1600	1	73	WAPA R.M.	790	1	5	11.111	0
79154	FLGORG1 11.500	1	73	WAPA R.M.	790	1	24	56.1	0
79155	FLGORG2 11.500	1	73	WAPA R.M.	790	1	24	56.1	0
79156	FLGORG3 11.500	1	73	WAPA R.M.	790	1	24	56.1	0
79157	BMESA1-2 11.500	1	73	WAPA R.M.	790	1	19	44	0
79157	BMESA1-2 11.500	2	73	WAPA R.M.	790	1	19	44	0
79158	NUCLA 1 13.800	1	73	WAPA R.M.	790	0	0	12	8
79159	NUCLA 2 13.800	1	73	WAPA R.M.	790	0	0	12	8
79160	NUCLA 3 13.800	1	73	WAPA R.M.	790	0	0	12	8
79161	NUCLA 4 13.800	1	73	WAPA R.M.	790	0	0	74	46
79162	CRYSTAL 11.500	1	73	WAPA R.M.	790	1	15	35	0
79164	TOWAOC 6.9000	1	73	WAPA R.M.	790	1	6	12.1	0
79166	MOLINA-L 4.2000	1	73	WAPA R.M.	790	1	2	4.9	0
79172	MOLINA-U 4.2000	1	73	WAPA R.M.	790	1	4	8.6	0
79176	MCPHEE 2.4000	1	73	WAPA R.M.	790	1	1	1.3	0
79251	QFATLAS1 13.800	1	73	WAPA R.M.	790	0	0	32.7	15
79251	QFATLAS1 13.800	2	73	WAPA R.M.	790	0	0	15.4	3

79252	QFATLAS2	13.800	3	73	WAPA R.M.	790	0	0	15.4	3
79252	QFATLAS2	13.800	4	73	WAPA R.M.	790	0	0	15.4	3

APPENDIX F: Benchmark Cases San Luis Valley Load Tables

2026 Heavy Summer San Luis Valley Loads

Bus Number	Bus Name	Id	Area Num	Area Name	Zone Num	Zone Name	Owner Num	Owner Name	Pload (MW)	Qload (Mvar)
70024	ALMSA_ST 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	4.697	1.718
70025	ALMSA_TM 115.00	P2	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	6.419	1.764
70025	ALMSA_TM 115.00	P3	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	6.158	2.487
70028	ANSEL_TS 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	4.41	0.12
70029	ANTONITO 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	2.677	1.097
70029	ANTONITO 69.000	P3	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	1.452	0.053
72480	CARMEL 115.00	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	8.39	1.9
70092	CENTER 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	12.85	3.65
70118	COCENTER 69.000	MU	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	1.5	0.493
70129	CREEDE 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	3.45	-1.14
70143	DELNORTE 69.000	P2	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	1.526	0.935
70143	DELNORTE 69.000	P3	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	1.348	0.498
70187	FTGARLND 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	2.62	-0.209
70187	FTGARLND 69.000	P2	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	3.126	0.559
70187	FTGARLND 69.000	P3	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	1.206	0.295
70221	HILANDSL 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	0.69	-0.23
70228	HOMELAKE	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	1.851	1.214

	69.000									
70228	HOMELAKE 69.000	P2	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	5.589	2.826
70228	HOMELAKE 69.000	TS	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	3.34	0.97
70229	HOOPER 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	3.86	1.09
70509	KERBERCK 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	0.32	-0.012
70245	LAGARITA 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	6.43	1.82
70507	MEARSJCT 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	0.06	0.02
70289	MOFFAT 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	0.258	0.087
70289	MOFFAT 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	4.7	0.2
70292	MOSCA 69.000	NT	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	-7.942	0
70292	MOSCA 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	1.906	0.655
70600	OXCART 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	0.14	0
70325	PLAZA 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	10.9	3.09
70327	PONCHA 115.00	NT	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	-1.4	-1.01
70327	PONCHA 115.00	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	8.674	0.936
70360	RIOGRAND 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	3.089	1.48
70360	RIOGRAND 69.000	P2	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	2.24	1.61
70367	ROMEO 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	3.084	1.692
70367	ROMEO 69.000	P2	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	3.262	1.397
70506	SAGUACHE 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	2.464	-0.111
70375	SANLSVLY	TS	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	0.75	0.25

	230.00									
70379	SARGENT 115.00	P2	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	6.338	5.176
70383	SFORK_SL 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	2.76	-0.91
70932	SOLAR_GE 34.500	TS	70	PSCOLORADO	710	ZONESL	700	NON UTILITY	0.03	0
70411	STANLEY 115.00	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	5.76	0.48
70467	WAVERLY 115.00	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	3.9	0.54
72481	ZINZER 115.00	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	5.07	1.13

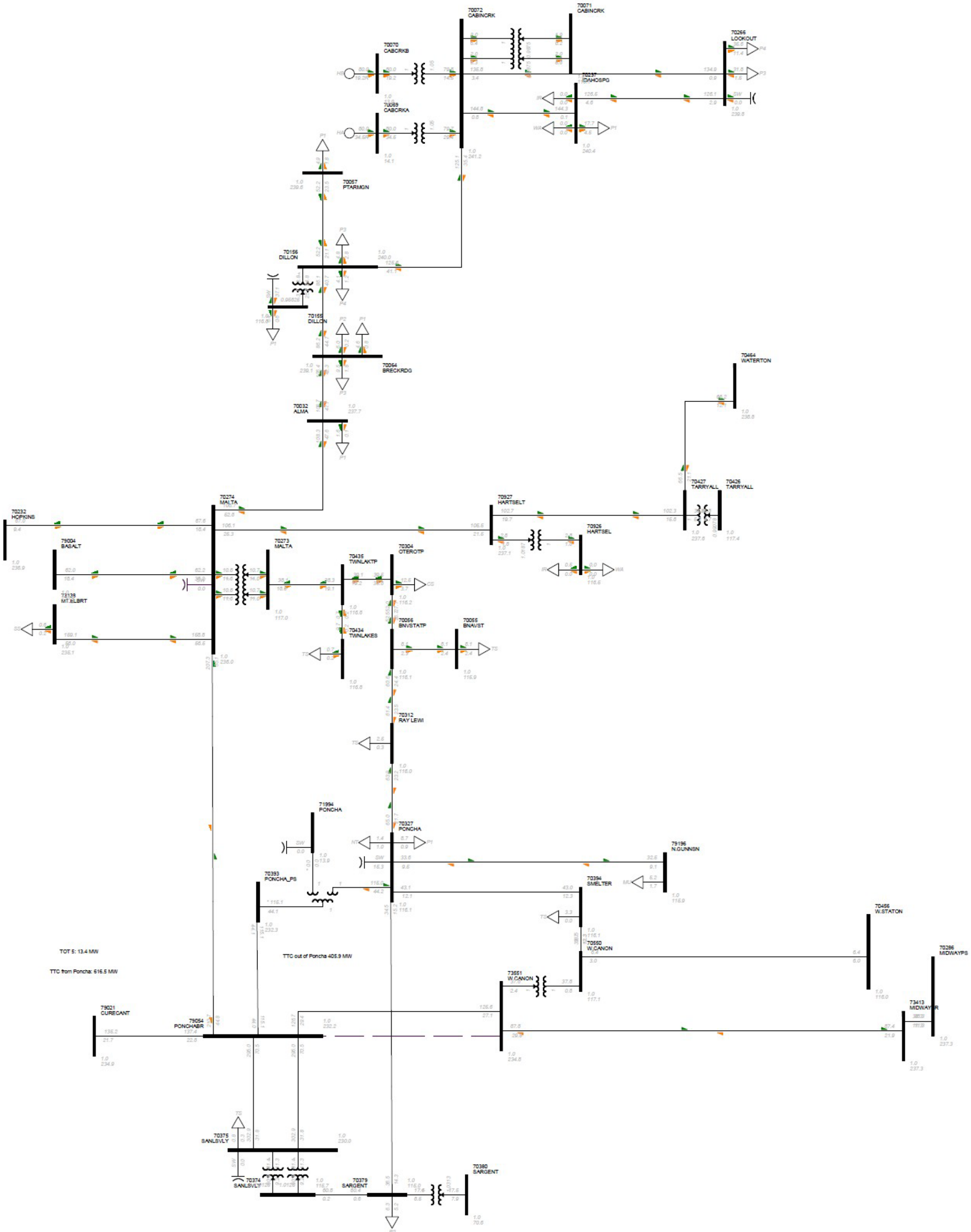
2026 Light Spring San Luis Valley Loads

Bus Number	Bus Name	Id	Area Num	Area Name	Zone Num	Zone Name	Owner Num	Owner Name	Pload (MW)	Qload (Mvar)
70024	ALMSA_ST 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	2.366	0.822
70025	ALMSA_TM 115.00	P2	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	3.229	0.765
70025	ALMSA_TM 115.00	P3	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	3.098	1.132
70028	ANSEL_TS 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	0.96	0.03
70029	ANTONITO 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	1.347	0.52
70029	ANTONITO 69.000	P3	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	0.732	0.013
72480	CARMEL 115.00	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	3.77	0.99
70092	CENTER 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	4.88	1.39
70118	COCENTER 69.000	MU	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	1.34	0.44
70129	CREEDE 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	1.64	-0.54
70143	DELNORTE 69.000	P2	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	0.768	0.456
70143	DELNORTE 69.000	P3	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	0.68	0.246
70187	FTGARLND 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	1.321	-0.124
70187	FTGARLND 69.000	P2	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	1.573	0.229
70187	FTGARLND 69.000	P3	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	0.608	0.145

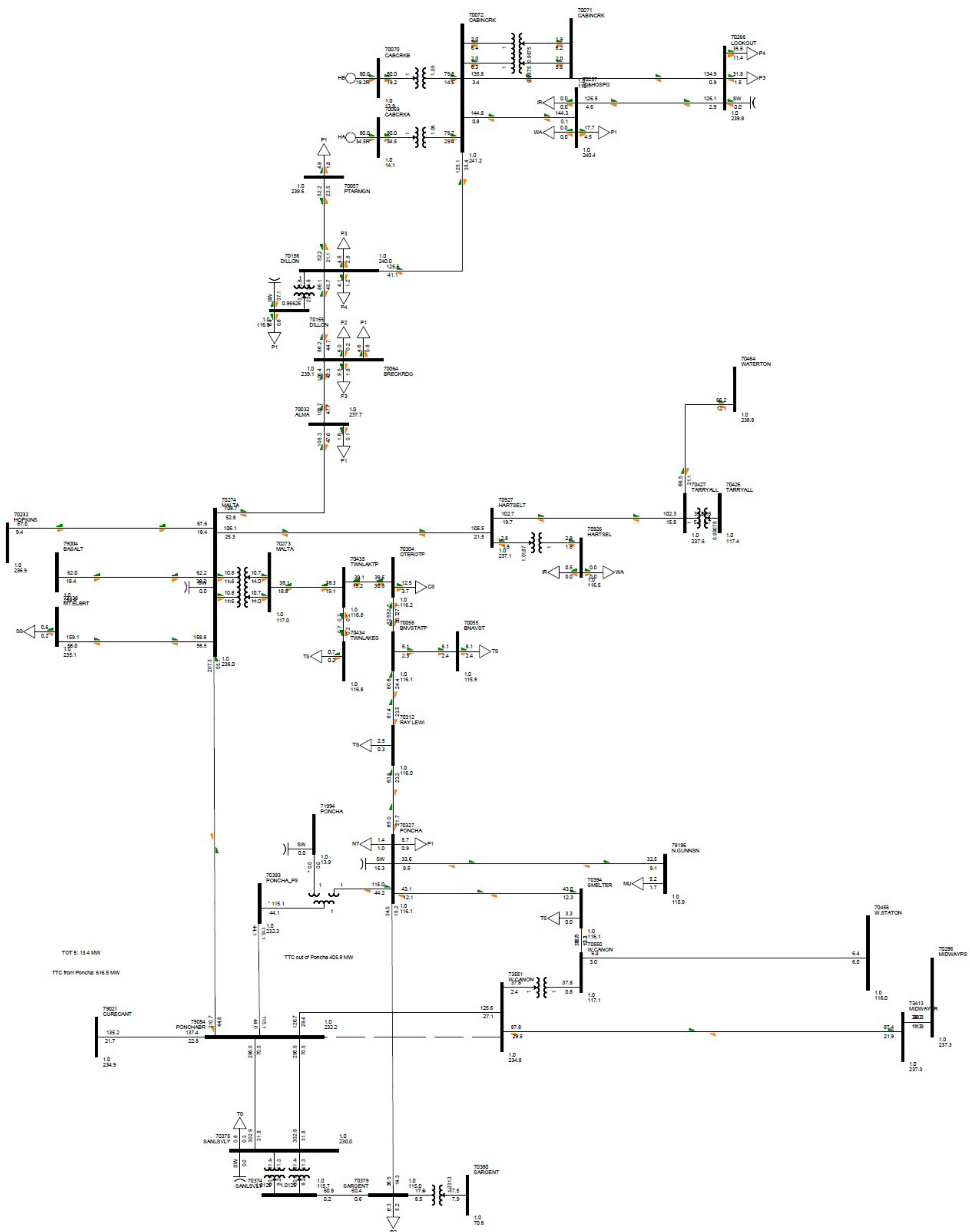
70221	HILANDSL 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	0.25	-0.08
70228	HOMELAKE 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	0.932	0.594
70228	HOMELAKE 69.000	P2	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	2.812	1.355
70228	HOMELAKE 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	1.21	0.35
70229	HOOPER 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	1.1	0.31
70932	IBERDROLA_PV34.500	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	0	0
70509	KERBERCK 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	0.161	-0.008
70245	LAGARITA 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	1.83	0.52
70507	MEARSJCT 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	0.04	0.01
70289	MOFFAT 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	0.13	0.043
70289	MOFFAT 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	1.39	0.06
70292	MOSCA 69.000	NT	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	-7.942	-2.098
70292	MOSCA 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	0.961	0.323
70600	OXCART 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	0.03	0
70325	PLAZA 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	6.01	1.7
70327	PONCHA 115.00	NT	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	-1.399	0.019
70327	PONCHA 115.00	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	4.366	0.295
70360	RIOGRAND 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	1.555	0.701
70360	RIOGRAND 69.000	P2	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	1.128	0.783
70367	ROMEO 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	1.544	0.812
70367	ROMEO 69.000	P2	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	1.638	0.677
70506	SAGUACHE 69.000	P1	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	1.242	-0.072
70375	SANLSVLY 230.00	TS	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	0.56	0.18
70379	SARGENT 115.00	P2	70	PSCOLORADO	710	ZONESL	65	PSCOLORADO	3.189	2.452
70383	SFORK_SL 69.000	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	0.98	-0.32
70411	STANLEY 115.00	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	1.77	0.15
70467	WAVERLY 115.00	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	0.93	0.13
72481	ZINZER 115.00	TS	70	PSCOLORADO	710	ZONESL	73	TRI-STATE G&	1.58	0.35

APPENDIX G: Craig Unit 1 Retirement Data

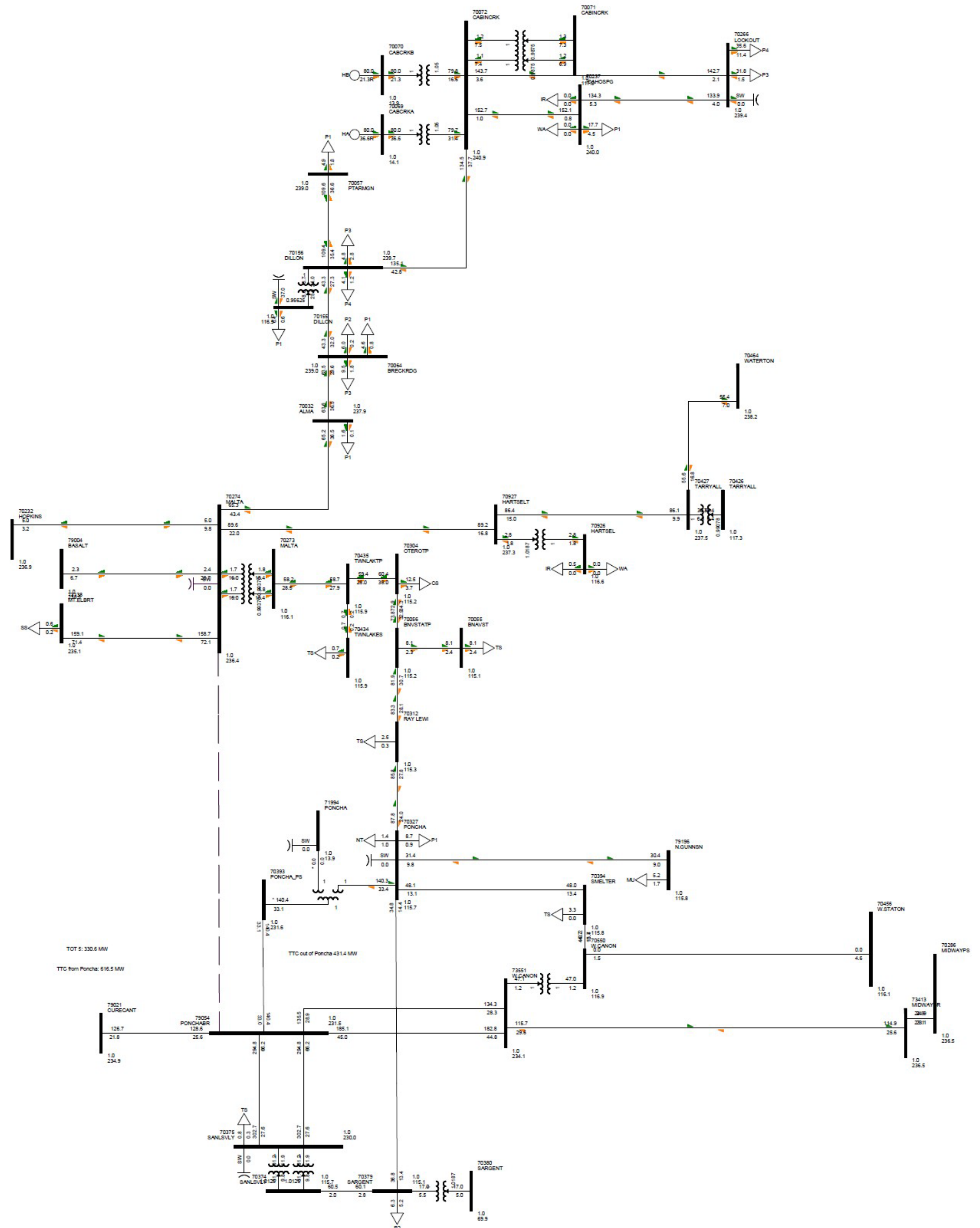
2026HS Alternative 1A TTC With Craig #1 In-Service



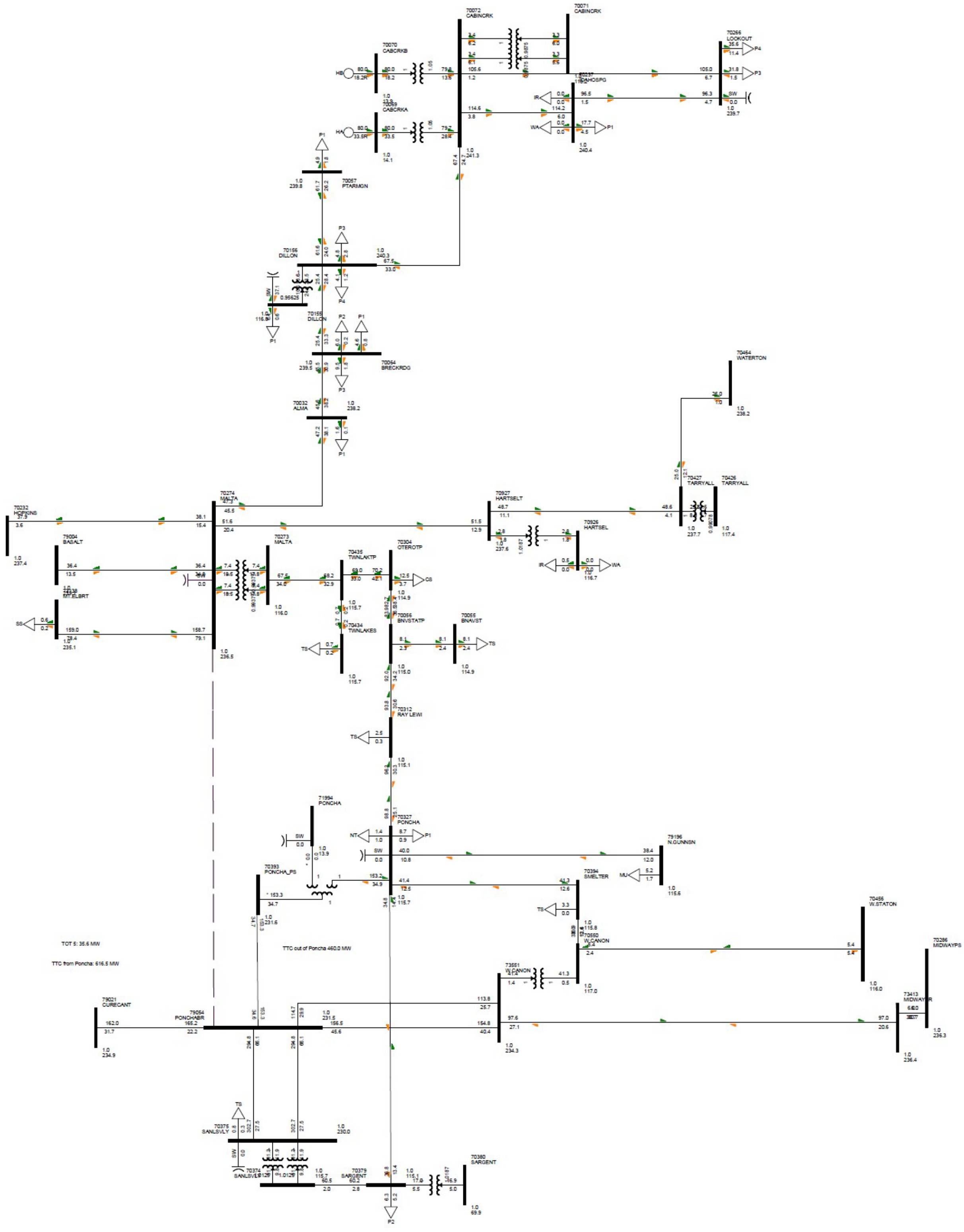
2026HS Alternative 1A TTC With Craig #1 Out-Of-Service



2026HS Alternative 2A TTC With Craig #1 In-Service



2026HS Alternative 2A TTC With Craig #1 Out-Of-Service



APPENDIX H: TOT 5 Stressed Data

Tables below are summary of TOT 5 Stressed findings

Case	Added Gen	TOT 5 (MW)	PON (M)	Limiting Element	Contingency	% Load	Element Rating (MVA)	Comments
BM	110	1000 MW	-44.3	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	100.0%	60*	Terminal Equipment Limitations
BM	325	1000 MW	-256.1	Buena Vista - Ray Lewis Tap 115 kV	Poncha-Canon West 230 kV	102.6%	115	90F
BM	375	1000 MW	-304.8	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	100.0%	120	
BM	75	1100 MW	-9.4	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	100.7%	60*	Terminal Equipment Limitations
BM	300	1100 MW	-231.7	Buena Vista - Ray Lewis Tap 115 kV	Poncha-Canon West 230 kV	102.6%	115	90F
BM	325	1100 MW	-256.1	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	101.4%	120	
BM	50	1200 MW	15.5	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	105.7%	60*	Terminal Equipment Limitations
BM	275	1200 MW	-207.3	Buena Vista - Ray Lewis Tap 115 kV	Poncha-Canon West 230 kV	102.0%	115	90F
BM	300	1200 MW	-231.7	Briargate S - Cottonwood S 115kV	Cottonwood N to Kettle Creek S 115 kV	100.0%	150	Normal Rating (97F)
BM	300	1200 MW	-231.7	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	100.0%	120	

Case	Added Gen	TOT 5 (MW)	PON (M)	Limiting Element	Contingency	% Load	Element Rating (MVA)	Comments
BM w/ BH	125	1000 MW	-59.2	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	102.0%	60*	Terminal Equipment Limitations
BM w/ BH	300	1000 MW	-231.7	Buena Vista - Ray Lewis Tap 115 kV	Poncha-Canon West 230 kV	97.2%	115	90F
BM w/ BH	350	1000 MW	-280.5	Poncha - Ray Lewis Tap 115 kV	Poncha-Canon West 230 kV	107.4%	120	90F
BM w/ BH	350	1000 MW	-280.5	W. Canon 230/115 T1	Canon West - Midway BR 230 kV	100.0%	100	
BM w/ BH	100	1100 MW	-34.4	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	106.0%	60*	Terminal Equipment Limitations
BM w/ BH	275	1100 MW	-207.2	Buena Vista - Ray Lewis Tap 115 kV	Poncha-Canon West 230 kV	96.5%	115	90F
BM w/ BH	325	1100 MW	-256.1	Poncha - Ray Lewis Tap 115 kV	Poncha-Canon West 230 kV	106.8%	120	90F
BM w/ BH	325	1100 MW	-256.1	W. Canon 230/115 T1	Canon West - Midway BR 230 kV	102.6%	100	
BM w/ BH	50	1200 MW	15.5	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	101.5%	60*	Terminal Equipment Limitations
BM w/ BH	275	1200 MW	-207.3	Buena Vista - Ray Lewis Tap 115 kV	Poncha-Canon West 230 kV	102.1%	115	90F
BM w/ BH	275	1200 MW	-207.3	W. Canon 230/115 T1	Canon West - Midway BR 230 kV	100.0%	100	
BM w/ BH	300	1200 MW	-231.7	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	100.0%	120	

Case	Added Gen	TOT 5 (MW)	PON (M)	Limiting Element	Contingency	% Load	Element Rating (MVA)	Comments
North	225	1000 MW	-158.1	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	100.0%	60*	Terminal Equipment Limitations
North	670	1000 MW	-587.1	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	100.0%	120	
North	670	1000 MW	-587.1	W.Canon 230/115 kV	Canon West - Midway BR 230 kV	100.0%	100*	
North	680	1000 MW	-596.5	Smeltertown- W. Canon	Poncha-Canon West 230 kV	100.0%	119	Switch Rating - Conductor Rated 141
North	175	1100 MW	-108.7	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	103.1%	60*	Terminal Equipment Limitations
North	610	1100 MW	-530.4	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	100.0%	120	
North	610	1100 MW	-530.4	Brairgate S - Cottonwood S 115 kV	Cottonwood N - Kettle Creek S 115 kV	100.0%	150	Normal Rating (97F)
North	620	1100 MW	-539.9	W.Canon 230/115 kV	Canon West - Midway BR 230 kV	100.0%	100*	
North	125	1200 MW	-59.2	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	103.3%	60*	Terminal Equipment Limitations
North	550	1200 MW	-473.3	Briargate S - Cottonwood S 115kV	Cottonwood N to Kettle Creek S 115 kV	100.0%	150	Normal Rating (97F)
North	560	1200 MW	-482.8	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	100.0%	120	
North	570	1200 MW	-492.3	W. Canon 230/115 T1	Poncha-Canon West 230 kV	100.0%	100	

Case	Added Gen	TOT 5 (MW)	PON (M)	Limiting Element	Contingency	% Load	Element Rating (MVA)	Comments
North w/ BH	225	1000 MW	-158.1	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	99.0%	60*	Terminal Equipment Limitations
North w/ BH	580	1000 MW	-501.9	W. Canon 230/115 T1	Canon West - Midway BR 230 kV	100.9%	100	
North w/ BH	670	1000 MW	-587.1	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	100.0%	120	
North w/ BH	680	1000 MW	-596.5	Smeltertown- W. Canon	Poncha-Canon West 230 kV	100.0%	119	Switch Rating - Conductor Rated 141
North w/ BH	200	1100 MW	-133.4	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	103.9%	60*	Terminal Equipment Limitations
North w/ BH	530	1100 MW	-454.2	W. Canon 230/115 T1	Canon West - Midway BR 230 kV	100.0%	100	
North w/ BH	610	1100 MW	-530.4	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	100.0%	120	
North w/ BH	610	1100 MW	-530.4	Briargate S - Cottonwood S 115kV	Cottonwood N to Kettle Creek S 115 kV	100.0%	150	Normal Rating (97F)
North w/ BH	150	1200 MW	-84.0	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	104.3%	60*	Terminal Equipment Limitations
North w/ BH	475	1200 MW	-401.4	W. Canon 230/115 T1	Canon West - Midway BR 230 kV	100.0%	100	
North w/ BH	550	1200 MW	-463.7	Briargate S - Cottonwood S 115kV	Cottonwood N to Kettle Creek S 115 kV	100.0%	150	Normal Rating (97F)
North w/ BH	560	1200 MW	-482.8	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	100.0%	120	

Case	Added Gen	TOT 5 (MW)	PON (M)	Limiting Element	Contingency	% Load	Element Rating (MVA)	Comments
East	300	1000 MW	-231.6	Briargate S - Cottonwood S 115kV	Cottonwood N to Kettle Creek S 115 kV	100.0%	150	Normal Rating (97F)
East	375	1000 MW	-304.7	Poncha - Smelter Town 115 kV	West Canon 230/115 kV	100.0%	60*	Terminal Equipment Limitations
East	620	1000 MW	-539.8	Buena Vista - Ray Lewis Tap 115 kV	Poncha-Canon West 230 kV	100.0%	115	90F
East	225	1100 MW	-158.0	Briargate S - Cottonwood S 115kV	Cottonwood N to Kettle Creek S 115 kV	100.0%	150	Normal Rating (97F)
East	350	1100 MW	-280.4	Poncha - Smelter Town 115 kV	West Canon 230/115 kV	100.0%	60*	Terminal Equipment Limitations
East	610	1100 MW	-530.4	Buena Vista - Ray Lewis Tap 115 kV	Poncha-Canon West 230 kV	100.0%	115	90F
East	200	1200 MW	-133.4	Briargate S - Cottonwood S 115kV	Cottonwood N to Kettle Creek S 115 kV	100.0%	150	Normal Rating (97F)
East	325	1200 MW	-256.1	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	100.0%	60*	Terminal Equipment Limitations
East	600	1200 MW	-520.9	Buena Vista - Ray Lewis Tap 115 kV	Poncha-Canon West 230 kV	100.0%	115	90F

Case	Added Gen	TOT 5 (MW)	PON (M)	Limiting Element	Contingency	% Load	Element Rating (MVA)	Comments
East w/ BH	300	1000 MW	-231.6	Briargate S - Cottonwood S 115kV	Cottonwood N to Kettle Creek S 115 kV	100.0%	150	Normal Rating (97F)
East w/ BH	400	1000 MW	-328.9	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	100.0%	60*	Terminal Equipment Limitations
East w/ BH	620	1000 MW	-539.8	Buena Vista - Ray Lewis Tap 115 kV	Poncha-Canon West 230 kV	100.0%	115	90F
East w/ BH	225	1100 MW	-158.0	Briargate S - Cottonwood S 115kV	Cottonwood N to Kettle Creek S 115 kV	100.0%	150	Normal Rating (97F)
East w/ BH	375	1100 MW	-304.7	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	102.5%	60*	Terminal Equipment Limitations
East w/ BH	610	1100 MW	-530.3	Buena Vista - Ray Lewis Tap 115 kV	Poncha-Canon West 230 kV	100.0%	115	90F
East w/ BH	200	1200 MW	-133.4	Briargate S - Cottonwood S 115kV	Cottonwood N to Kettle Creek S 115 kV	100.0%	150	Normal Rating (97F)
East w/ BH	325	1200 MW	-256.1	Poncha - Smelter Town 115 kV	Poncha-Canon West 230 kV	100.0%	60*	Terminal Equipment Limitations
East w/ BH	600	1200 MW	-520.9	Buena Vista - Ray Lewis Tap 115 kV	Poncha-Canon West 230 kV	100.0%	115	90F

APPENDIX I: Indicative Level Cost Estimates for Alternatives

Element	Description	Cost Est. (Millions)
SLV – Poncha 230kV #2 Line (Phase 1)	Construct a new 62-mile, 230kV single circuit overhead transmission line. Convert 9 miles of 69 kV to 230 kV. New 115/69 kV substation. Poncha substation additions. San Luis Valley substation additions.	**$75M**
Alternative 1: Poncha – Malta 230kV (Phase 2)	Construct approximately 52 miles of new single circuit 230kV OH transmission line. Will require new easements/ROW. New line terminations and associated equipment at Poncha and Malta Substations.	**$100M**
Alternative 2: Poncha – W.Canon – Midway 230kV (Phase 2)	Construct approximately 88 miles of new single circuit 230kV and 115kV OH transmission line. Will require new easements/ROW. New line terminations and associated equipment at Poncha, West Canon and Midway Substations.	**$170M**

Responsible Energy Plan Task Force Study Report

Analysis Performed and Prepared By:

Tri-State Generation & Transmission Association, Inc.
Transmission Planning
On Behalf of the Responsible Energy Plan Task Force

Accepted by CCPG on December 16, 2021

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1.0 EXECUTIVE SUMMARY

This report summarizes the studies completed under the scope of work for the Colorado Coordinated Planning Group's ("CCPG") Responsible Energy Plan Task Force ("REPTF"). The REPTF identified transmission alternatives that accommodates additional generation resources in eastern Colorado, increases Tri-State's ability to deliver power across Tri-State's four-state service area to ensure access to geographically diverse resources, and strengthens the rural Colorado transmission system. The purpose of the report is to summarize the ability of the transmission alternatives to:

1. accommodate at least 400 MW of new generation in eastern Colorado,
2. provide connectivity across Tri-State's four-state service area,
3. improve transmission system reliability in the Lamar area, and
4. mitigate generation curtailment in eastern Colorado under 230 kV prior outage conditions.

The results of the study indicate that several alternatives are capable of accommodating at least 400 MW of new generation in eastern Colorado, providing connectivity across Tri-State's four-state service area, improving transmission system reliability in the Lamar area, and mitigating generation curtailment in eastern Colorado under 230 kV prior outage conditions.

The most efficient, cost-effective alternatives to meet the objectives and needs were Alternatives 7 and 14. The most efficient, cost-effective alternative to meet the needs of multiple Colorado utilities was Alternative 6, albeit at a cost of over $1 billion. Alternative 6 provided an option for other Transmission Providers, who choose to participate, to utilize a portion of the project to meet their de-carbonization goals/needs. Some stakeholders believe the long-term reliability and system benefits provided by increased transmission connections and 345 kV construction make the expanded alternatives (4, 5, 6, 6B, and 8) worthy of consideration today. Advanced Transmission Technologies ("ATT") and Non-Wires Alternatives ("NWA") alone does not meet the objectives and needs.

The analysis included an evaluation of transmission system performance utilizing applicable reliability criteria, and sensitivity studies with the proposed Colorado's Power Pathway project ("CPP Project") in service and ATT (power flow control). Sensitivity analyses demonstrated:

1. The REPTF alternatives showed no negative interactions with the proposed CPP Project.
2. The proposed CPP Project improved injection capability at Story in all alternatives and at Burlington in three alternatives (5, 6B, and 8), and had no impact on injection capability at Lamar in all alternatives.
3. The utilization of ATT (power flow control) showed the potential to enhance injection capability.

However, the increased injection capability observed at Story and Burlington is not an accurate reflection of additional resources accommodated by the proposed CPP Project. This is due to the geographically diverse dispatch (not severely stressed) utilized on the proposed CPP Project due to unknown new resource size/locations, and associated reactive support or grid enforcements technologies that may be required/constructed. Rather, the increased injection capability represents the ability of REPTF alternatives to leverage an unstressed proposed CPP project.

Each of the alternatives evaluated would meet multiple objectives and needs, and would significantly improve the reliability of the eastern Colorado transmission network by providing additional transmission infrastructure to the Burlington and Lamar areas. In terms of overall system reliability, including multiple connections between transmission systems and between the eastern Colorado transmission system and the Front Range load centers provides a more robust transmission system. However, this is can only be accomplished at an increased financial cost. No single alternative was identified as preferred due to numerous considerations that the REPTF agreed should be taken into account, such as cost, participation, existing needs, and future needs.

2.0 BACKGROUND

In 2019, Colorado passed House Bill 19-1261 (HB19-1261) which gave authority to the Air Quality Control Commission to draw rules for implementation of economy wide greenhouse gas reduction, which will impact the resource plans of Colorado utilities. Specifically, Colorado's statewide goals are to reduce greenhouse gas emissions by at least 26% by 2025, 50% by 2030, and 90% by 2050 from levels that existed in 2005. Additionally, Colorado passed Senate Bill 19-236 (SB19-236) which requires Tri-State Generation & Transmission, Inc. ("Tri-State") to submit electric resource plans for Colorado Public Utilities Commission ("Commission") approval.

In January 2020, Tri-State announced its Responsible Energy Plan ("REP"), a transition to clean energy that will provide reliable, affordable, and responsible electricity for its member systems. REP goals include reduced emissions, increased clean energy, and increased member flexibility, among others. The REP includes early retirement of coal-fired electric generating stations[1] and the Colowyo Mine in Colorado by 2030, in support of Colorado's HB19-1261 emission reduction goals. Tri-State filed an Electric Resource Plan[2] ("ERP") in December 2020 describing the generation and transmission plans necessary to meet REP goals. The preferred alternative in the ERP filing was an 80% carbon reduction alternative by 2030, which identified 400 MW of resource needs in eastern Colorado.

Other Colorado utilities have also announced similar plans, or indicated support for looking at plans, to reach Colorado's carbon reduction goals. In 2018, Xcel Energy ("PSCo") announced their clean energy vision to deliver 100 percent carbon free electricity to customers by 2050, with an interim goal of an 80 percent reduction in carbon dioxide emissions by 2030 relative to 2005 levels. In November 2020, Black Hills Energy announced its intention to also meet certain carbon reduction goals on its system. Non-Commission regulated Colorado utilities have also indicated support for looking at plans to reach Colorado's carbon reduction goals.

In response to the Colorado legislation and utility plans, working alongside stakeholders and joint planning bodies, the Colorado Coordinated Planning Group ("CCPG") has facilitated several major study efforts over the last decade, many focused on eastern Colorado, including, but not limited to, the Lamar-Front Range Task Forces (2013 and 2019), the Rush Creek Task Force (2017), and the 80x30 Task Force (2021). As a result of the study efforts, PSCo has proposed the Colorado's Power Pathway project ("CPP Project") with the Commission for approval. The proposed CPP Project includes approximately 560 miles of double-circuit 345 kV transmission that will facilitate the delivery of new renewable resources from eastern Colorado to the Front Range at an estimated cost of $1.7 billion. After thorough evaluation, Tri-State determined that participation in the proposed CPP

[1] Craig Unit 1 by end of 2025. Craig Unit 2 by end of 2028. Craig Unit 3 by 2030.

[2] Tri-State's ERP proceeding is currently pending before the Colorado Public Utilities Commission. Given that the Commission has not yet approved a final resource plan with respect to Tri-State, the assumptions in this Study Report related to Tri-State's generation resources generally reflect Tri-State's REP and preferred ERP scenario. They are not intended to capture subsequent developments that may occur in the ERP proceeding pending before the Colorado Public Utilities Commission.

Project was not in the best interest of its members, however Tri-State believes there is value in other Front Range electric utilities pursuing the project.

Due to shorter timelines associated with development and construction of renewable resources, such as wind and solar, in relation to traditional fossil fuel plants, transmission development must be pursued well in advance of resource development so the resources can be accommodated. To aid in resolving this dilemma, the CCPG launched the Responsible Energy Plan Task Force ("REPTF") in March 2021 to provide a forum for all stakeholders to collaboratively identify transmission alternatives that will enable Colorado utilities to meet the state's de-carbonization goals. The REPTF identified transmission alternatives that accommodates additional generation resources in eastern Colorado, increases Tri-State's ability to deliver power across Tri-State's four-state service area to ensure access to geographically diverse resources, and strengthens the rural Colorado transmission system.

3.0 STUDY OBJECTIVE AND NEEDS

The REPTF developed a formal study scoping document, which identifies the study purpose, background, process, models, methodology, alternatives, sensitivities, cost estimates, and schedule. The purpose of this study is to analyze the costs and benefits of transmission alternatives in eastern Colorado to meet the following objectives:

1. Accommodate generation resources (at least 400 MW) in eastern Colorado necessary to meet preferred 2030 carbon reduction scenario in the recently filed Electric Resource Plan to meet public policy goals
2. Increase ability to deliver power across Tri-State's four-state service area to ensure access to geographically diverse resources
3. Strengthen rural Colorado transmission system (improve reliability)

The Tri-State transmission system is not contiguous across its four-state service area. A gap in the southeastern Colorado transmission system limits Tri-State's ability to move and deliver power from geographically diverse resources. Figure 1 shows the complete southeastern Colorado transmission system (left), and the gap in Tri-State's transmission system in southeast Colorado (right).

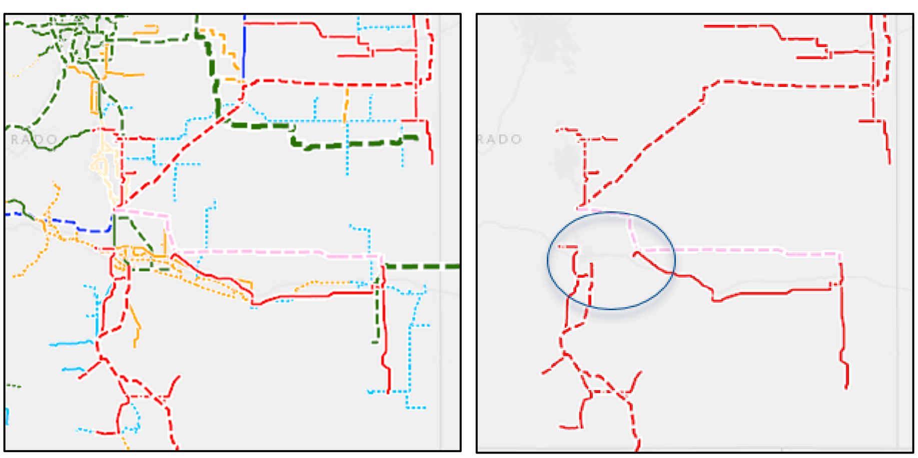

Figure 1: Transmission Gap

The rural eastern Colorado transmission system, in both the Lamar and Limon/Burlington areas, is best described as a single 230 kV system with an underlying 115kV system. In the Lamar area, an outage of the Lamar – Boone 230 kV line results in southeast Colorado being served radially from the Boone – La Junta – Willow Creek 115 kV line. Additionally, under the Lamar – Boone 230 kV line outage, all generation in the Lamar area is tripped offline, and the DC tie is reduced to 0 MW, due to limited export capability on the remaining 115 kV line. When the 230 kV line is lost the ability to reliably operate the system is compromised and, in some cases, requires load to be shed to maintain system stability. In summary, the existing Lamar transmission system with a single 115 kV circuit in parallel with a single 230 kV circuit creates operational and maintenance challenges.

The Limon and Burlington areas are connected by a single 230 kV loop connecting to the Story Substation in the north and to the Midway Substation in the south. The 230 kV loop supports an underlying 115 kV load-serving system with connections at the Big Sandy (near Limon), Burlington, Wray, North Yuma, and Beaver Creek (near Story) Substations. Under the planned or unplanned outage of any segment of the 230 kV loop, the generation connected to this loop (which now exceeds 500 MW), is curtailed to prepare for a second 230 kV line outage which would force all area generation onto the underlying 115 kV system. The increased generation development on a transmission system designed for rural load serving has created operational and maintenance challenges.

To accomplish the REPTF objectives, the following needs were specifically identified:

1. Accommodate at least 400 MW[3] of new generation in eastern Colorado
2. Provide connectivity across Tri-State's four state service area, which currently is not connected in southeast Colorado.
3. Improve Lamar transmission system reliability, specifically related to the Lamar-Boone 230 kV line outage.
4. Mitigate generation curtailment in eastern Colorado under 230 kV prior outage conditions.

This study included steady state power flow analyses. System parameters such as facility loadings and voltages were monitored within the study area consistent with North American Electric Reliability Corporation ("NERC") and WECC standards.

4.0 STUDY PROCESS

The study was conducted through the REPTF of the CCPG. The CCPG is an open transmission planning forum whose core mission is "*to assure a high degree of reliability through cooperative planning, joint development, and coordinated operation of the high voltage transmission system in the Rocky Mountain Region.*"[4] The CCPG has working groups that are divided into Subcommittees, Work Groups, and Task Forces. The purpose of a Task Force is to evaluate a specific issue within the CCPG footprint over a relatively

[3] 400 MW is viewed as the "floor" for generation accommodation. Generation accommodated beyond 400 MW is considered an opportunity for future, long term resource growth and/or meet the resource needs of multiple Colorado utilities.
[4] CCPG Charter, http://regplanning.westconnect.com/ccpg.htm

short period of time, as compared to the subcommittees and work groups that evaluate issues generally on an ongoing basis. The REPTF kickoff meeting was held in April 2021, and participation has been open to any interested stakeholders. To ensure transparency, meetings have been held regularly, generally monthly, and meeting materials (agendas, presentations, meeting notes) are publicly posted on the Responsible Energy Plan Task Force web page, located within the WestConnect website[5]. Several meetings were held that included participation from a wide variety of stakeholders, including:

- Avangrid
- Basin Electric Power Cooperative
- Black Hills Energy
- Buckyball Systems
- Colorado Springs Utilities
- Dietze and Davis, on behalf of Independent Power Producers
- Enel Green Power
- Energy Strategies
- Grid Numerics
- Grid Resiliency Consulting
- Grid Strategies
- Interwest Energy Alliance
- Invenergy
- National Renewable Solutions
- New Energy Consulting
- NextEra Energy
- Office of Consumer Counsel
- Outshine Energy
- Platte River Power Authority
- SR3 Engineering
- Staff of the Colorado Public Utilities Commission
- Tri-State Generation & Transmission, Inc.
- Western Resource Advocates
- Public Service Company of Colorado (Xcel Energy or PSCo)

[5] REPTF Website, http://regplanning.westconnect.com/ccpg_responsible_energy_plan_tf.htm

A complete list of stakeholders that have participated in one or more REPTF meetings is included in Appendix A.

Tri-State acted as the facilitator in the study effort by both conducting and presenting the studies and their results. The study scope and all alternatives, sensitivities and scenario studies were agreed to by the REPTF participants.

To analyze the benefit of a given transmission alternative, the new generation accommodated was determined for each alternative as well as the benchmark base case. The generation injection capability was determined by increasing generation output in eastern Colorado until a transmission constraint was reached. The generation injection capability was determined to be the new generation accommodated.

For most alternatives, additional limitations were found by assuming that the first limitations were mitigated in some manner. It is important to note that in an injection study of this scope, the results can vary significantly based on how existing generation is dispatched and where new generation is added on the system. The injection capabilities that were determined should be viewed more on a relative basis to compare alternatives rather than absolute values of capability. If any transmission alternative were to be pursued, additional studies would be performed through the transmission provider's Large Generator Interconnection Procedures.

The REPTF recognizes that there may be other benefits for the alternatives studied. These potential benefits, that were not evaluated, include Adjusted Production Cost savings, reduced capacity cost due to reduced transmission losses, avoided or delayed reliability projects, mitigation of transmission outage costs, assumed benefit of mandated reliability projects, marginal energy losses, operating reserves considerations, and increased wheeling revenues. Instead, the REPTF study focused on the reliability impacts and injection capabilities of alternatives.

5.0 ADVANCED TRANSMISSION TECHNOLOGIES/NON-WIRES ALTERNATIVES

The REPTF acknowledged the significant interest from stakeholders in the utility industry in Advanced Transmission Technologies ("ATT") and Non-Wires Alternatives ("NWA"), and held several discussions on the different types of ATT and NWA, their purposes/uses, and their applicability. The discussions assisted the REPTF in determining which ATT and NWA should considered, and in which situations.

In general, ATT and NWA can be grouped into several areas: (1) High voltage Direct Current ("HVDC"), including underground installations within existing railroad ROWs; (2) Dynamic line ratings ("DLR"); (3) Transmission system topology optimization; (4) Power flow control technologies; (5) Energy Storage, and (6) Composite Core Conductors.

5.1 High Voltage Direct Current

A HVDC system utilizes direct current ("DC"), rather than standard alternating current ("AC"), for bulk transmission of electrical power. Examples of HVDC include the DC Ties (such as Lamar (210 MW)) between the Eastern and Western Interconnection, and the Pacific DC Intertie (3100 MW) between the Pacific Northwest and Los Angeles.

Advantages include:

- allows power transmission between AC transmission systems that are not synchronized (different frequencies),
- at long distances, can have lower overall investment cost and losses than an equivalent AC transmission,
- reduced capacitance on long underground cable or long overhead conductor,
- can help system stability by preventing cascading failures

Disadvantages include cost, conversion, switching, control, availability, and maintenance. Generally, long line lengths (>200 miles) are required before a DC alternative will become cost competitive, but the actual length is highly dependent on the specifics (power rating, overhead vs underground, etc.) of the project.

5.2 Dynamic Line Ratings

DLR is the adoption of transmission line ratings based upon real-time monitoring of equipment and/or weather conditions (ambient temperature, wind speed, wind direction, etc.). This is in contrast to transmission planning, which is performed with static line ratings based upon generally conservative weather assumptions.

Advantages include utilization of unused line capacity under cooler and/or windier conditions, leading to reduce line congestion and potential for deferred transmission investment to reduce real-time congestion.

Disadvantages/challenges include identification of suitable lines to apply DLR, increased operational complexity, cost to implement, and the need to statically or dynamically adapt system protection settings to meet NERC compliance standards.

5.3 Transmission System Topology Optimization

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

Advantages include low cost to perform due to existing control infrastructure and reduced congestion.

Disadvantages include potential for reduced reliability to system load when opening circuit breakers on transmission systems that don't include multiple paths (transmission lines) for power to flow (i.e. reduces reliability to system load).

5.4 Power Flow Control Technologies

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

5.4.1 Phase Angle Regulator ("PAR") or Phase-Shifting Transformer ("PST")

PAR and PST adjust the power angle (δ) to push or pull power flow on the transmission system. The primary purposes are to reduce/remove overloads under contingency conditions, force contractual/scheduled power flows, and/or mitigate loop or unscheduled flows. The challenges include voltage limitations, and the potential to create loop flow issues on parallel systems. PAR and PST are both very mature technologies and widely implemented within WECC to mitigate loop flows issues across the Western Interconnection.

5.4.2 FACTS (Shunt Compensation)

FACTS (shunt compensation) devices are used to control voltages on the transmission system and includes shunt reactors, shunt capacitors, Static Synchronous Compensators ("STATCOM"), and Static VAR Compensators ("SVC").

Shunt reactors depress system voltages, typically in response to high voltages caused by the Ferranti Effect and/or underground cable. The challenges include limited flexibility since shunt reactors are sized for the location/application and are not dynamic. However, they are a very mature technology and widely implemented on the transmission system.

Shunt capacitors support/increase voltages, typically in response to lower voltages caused by heavy system loading, or to improve load power factor. The challenges include limited flexibility since shunt capacitors are sized for the location/application and are not dynamic. However, they are a very mature technology and widely implemented on the transmission system.

STATCOMs are power electronics voltage-source converters that can act as a source or sink of reactive power, thereby supporting or depressing system voltages. STATCOMs provide dynamic voltage support and improve voltage stability on the transmissions system. The challenges include the higher cost in relation to static shunt devices. However, they are a very mature technology and widely implemented on the transmission system.

SVCs are dynamically controllable parallel reactance that can act as a source or sink of reactive power, thereby supporting or depressing system voltages. SVCs provide dynamic voltage support and improve voltage stability on the transmissions system. The challenges include the higher cost in relation to static shunt devices and slower dynamic response in relation to STATCOMs. However, they are a very mature technology and widely implemented on the transmission system.

5.4.3 FACTS (Series Compensation)

FACTS (series compensation) devices are used to control/influence power flow on the transmission system and includes series reactors, series (fixed and variable) capacitors, Static Synchronous Series Compensators ("SSSC"), and Distributed Series Compensator ("DSC").

Series reactors increase the impedance (+jX) of a transmission path and are used to reduce flows under contingency or reduce/limit short circuit current. The challenges include limited flexibility since series reactors are sized for the location/application, are not dynamic, and result in increased system losses when in operation. However, they are low cost and a very mature technology and widely implemented on the transmission system.

Series (fixed/variable) capacitors decrease the impedance (-jX) of a transmission path and are used to improve angular/voltage stability and provide better power sharing between parallel paths. Series variable capacitors are effective at improving damping of inter-area oscillation modes. The challenges include limited flexibility since series capacitors are sized for the location/application, are not dynamic, and increase potential for sub-synchronous interactions with Type 3 and 4 wind turbines. However, they are a very mature technology and implemented on the transmission system.

SSSCs inject sinusoidal voltages in series with the line, which acts as an inductive (+jX) or capacitive (-jX) reactance. SSSCs provide dynamic series compensation and can improve voltage stability on the transmissions system. Modular SSSCs have the advantage of being re-deployable where needed on the transmission system. SSSC are a newer technology and not widely implemented on the transmission system at this time.

DSCs are the single-phase model of a SSSC and have the same functionality. DSCs are a newer technology and not widely implemented on the transmission system at this time.

5.4.4 FACTS (Series + Shunt Compensation)

The Unified Power Flow Controller ("UPFC") is a FACTS device include series and shunt compensation. UPFC is a combination of a STATCOM and a SSSC coupled via a common DC voltage link. UPFC are a newer technology and not widely implemented on the transmission system. Only five installations exist in the world due to the unique system conditions required to justify a UPFC.

5.5 Energy Storage

Energy storage technologies are a means to capture and store energy for use on the transmission system. Energy storage technologies can help influence flow through a given path through charging and discharging cycles, enable load management, store excess resources, and/or provide voltage support. Charging cycles can provide short term reduction in curtailment. The challenges with energy storage include costs and the ability of energy storage to deliver resources from remote generation sites to load centers.

5.6 Composite Core Conductors

Composite core conductors are a newer type of conductor capable of higher operating temperatures (up to 200 deg C) with reduced sag. Advantages include higher rating (capacity) and lower impedance resulting in reduced losses. Disadvantages/challenges include increased up-front material cost, substation terminal equipment limiting use of higher line capacity, and maintenance concerns due to lack of inventory in emergency replacement conditions. Composite core conductors are not widely implemented on the transmission system and have primarily been utilized in select re-conductor projects where right-of-way challenges exist.

6.0 MODEL DEVELOPMENT

6.1 Base Cases

The following ten-year benchmark base cases were used for the REPTF studies.

- 2031 Heavy Summer Base Case (WECC Approved, 2031HS1a)

The participants of the REPTF reviewed the models for accuracy and provided modifications to the cases to accurately reflect the topology, load, and generation within the CCPG footprint. Case modifications were provided by Tri-State, Black Hills Colorado Electric ("BHC"), Colorado Springs Utilities ("CSU"), and Western Area Power Administration ("WAPA"). PSCo and Platte River Power Authority ("PRPA") reviewed the case but had no modifications.

6.2 Generation

The following planned generation additions and retirements[6] were included in the base models.

- BHC
    - G29 (Wind, 200 MW, 2023)
- PSCo
    - Cheyenne Ridge Wind (500 MW, 2021)
    - Bronco Plains Wind (300 MW, 2021)
    - Comanche 1 Retirement (2022)
    - CEP Generation (2023)
        - Tundra 345 kV
            - CEP6 (Solar, 250 MW; BESS, 125 MW)
        - Mirasol 230 kV
            - CEP5 (Solar, 200 MW; BESS, 100 MW)

[6] Only publicly announced generation retirements were considered in the base study model. Further generation retirements outside the eastern Colorado study area are not expected to impact this study.

        - Midway 230 kV
            - CEP (Solar, 100 MW)
    - Comanche 2 Retirement (2025)
    - Hayden 1 Retirement (2028)
    - Hayden 2 Retirement (2027)
- Tri-State
    - Crossing Trails Wind Farm (104 MW, 2021)[7]
    - Niyol Wind Farm (201 MW, 2021)
    - Spanish Peaks Solar (100 MW, 2023)
    - Craig 1 Retirement (2025)
    - Craig 2 Retirement (2028)
    - Craig 3 Retirement (2029)
- CSU
    - Williams Creek Solar (60 MW, 2020)
    - Pike Solar (175 MW, 2023)

Generation in the benchmark base cases was reviewed and modified in accordance with agreed upon assumptions by the REPTF which stressed the transmission system in eastern Colorado. Accordingly, the existing and planned generating plants in the study footprint were dispatched as noted below.

- Summer Peak Case Assumptions
    - Lamar Site Area: 90% wind rated capacity (285 MW); 0% DC capacity (0 MW)
    - Comanche Area: 65% solar rated capacity (373 MW); 100% conventional rated capacity (780 MW)
    - Big Sandy/Burlington Area: 80-90% wind rated capacity (445 MW), 90% conventional rated capacity (214 MW)
    - Missile Site/Rush Creek Area: 43% wind rated capacity (856 MW); 62% solar rated capacity (33 MW)
        - For networked Rush Creek Gen-Tie scenarios: 72% wind rated capacity (1420 MW)
    - Pawnee Site Area: 20% wind rated capacity (121 MW), 85% conventional rated capacity (701 MW)

[7] Crossing Trails Wind Farm reached full operation during the REPTF analysis.

A detailed list of the generation in Areas 70 and Area 73 in the benchmark case model can be found in the Appendix B.

6.3 Topology

The following significant transmission projects were included in the base models.

- BHC
  - West Station-Desert Cove-Fountain Valley-Midway 115 kV line rebuild
  - West Station-Canon City 115 kV line
- PSCo
  - Mirasol Substation along Comanche-Midway 230 kV line
  - Tundra Substation along Comanche-Daniels Park 345 kV line
  - Monument-Flying Horse 115 kV Line Reactor
- Tri-State
  - Fuller 230/115kV Transmission #2

6.4 Load

Loads in the benchmark cases were modified to reflect the latest load forecasts in the study area. The 2031 Heavy Summer case represents the expected summer peak forecast for 2031.

7.0 METHODOLOGY

7.1 Contingencies

All applicable NERC TPL-001-4 Category P0 (system intact, N-0) and Category P1 (single contingency, N-1) contingencies were simulated. Some selected NERC Category P2 disturbances were performed. A full contingency list can be found in Appendix C.

7.2 Monitoring

The following system parameters were monitored during the study:

1. All buses, lines, and transformers with base voltages equal to or greater than 44 kV in the Colorado power flow areas 70 and 73 will be monitored in all study cases.
2. Post contingency element loadings will only be tabulated in each alternative when an element rating is exceeded, and the loading increase is at least 1% from the benchmark case contingency. Specifically, if an element was overloaded in the benchmark case and increased no more than 1% in an alternative case for the same contingency, the overload will not be reported.

7.3 Performance Criteria

The transmission system was held to applicable NERC, WECC, and utilities standards. The following performance criteria was applied for steady state power flow analysis:

- **NERC TPL-001-4 Category P0**
  - Power Flow Solution Settings
    - Tap Adjustment: Stepping
    - Switch Shunt Adjustments: Enabled
    - Adjust Phase Shifter: Enabled
  - Voltage Criteria:
    - Acceptable Range: 0.95 – 1.05 per unit
    - Deviation Limit: n/a
  - Loading Criteria:
    - Transmission: 100% of continuous rating
    - Transformer: 100% of continuous rating or highest 65°C rating, whichever is more limiting
- **NERC TPL-001-4 Category P1 (N-1, Single Contingency)**
  - Power Flow Solution Settings
    - Tap Adjustment: Stepping
    - Switch Shunt Adjustments: Locked
    - Adjust Phase Shifter: Locked
  - Voltage Criteria:
    - Acceptable Range: 0.90 – 1.10 per unit
    - Deviation Limit: 8%
  - Loading Criteria:
    - Transmission: 100% of continuous rating
    - Transformer: 100% of continuous rating or highest 65°C rating[8], whichever is more limiting
- **NERC TPL-001-4 Category P2-P7 (N-n, Multiple Contingency)**
  - Power Flow Solution Settings
    - Tap Adjustment: Stepping
    - Switch Shunt Adjustments: Locked

[8] Xcel Energy transformers utilized 4-hour emergency ratings.

    - Adjust Phase Shifter: Locked
  - Voltage Criteria:
    - Acceptable Range: 0.90 – 1.10 per unit
    - Deviation Limit: n/a
  - Loading Criteria:
    - Transmission: 100% of continuous rating
    - Transformer: 100% of continuous rating or highest 65°C rating[9], whichever is more limiting

8.0 BENCHMARK CASE

8.1 Heavy Summer Case

The 2031 Heavy Summer case was benchmarked by increasing individual generation injection sites at Lamar, Burlington, and Wray 230 kV Substations. The generation injection was modeled assuming 0.95 lead/lag VAR capability. The generation injection was scheduled to western Colorado by reducing generation. Contingency analysis was performed with no generation injection and at varying generation injection levels, in 10 MW increments, up to 150 MW. No reactive voltage support was added to the case to support the higher power transfers associated with additional generation injection.

Contingency analysis demonstrated that prior to any generation injection, no transmission system elements in eastern Colorado, Denver Metro, or Colorado Springs exceeded thermal limits.

To determine existing generation injection capability, the local generation in the area of each injection site was separately stressed prior to adding new generation. As generation injection increased, new overloads were created. Specifically, new overloads developed along the following transmission lines:

- Story Injection Site, 0 MW
  - Limiting Element – Smoky Hill – Missile Site 345 kV
  - *Limiting Contingency* – Missile Site – Daniels Park 345 kV
- Big Sandy Injection Site, 0 MW
  - Limiting Element – Big Sandy – Woodrow – Beaver Creek 115 kV
  - *Limiting Contingency* – Lincoln – Midway 230 kV
- Burlington Injection Site, 0 MW
  - Limiting Element – Big Sandy – Woodrow – Beaver Creek 115 kV
  - *Limiting Contingency* – Lincoln – Midway 230 kV

[9] Xcel Energy transformers utilized 4-hour emergency ratings.

- Wray Injection Site, 0 MW
  - Limiting Element – Big Sandy – Woodrow – Beaver Creek 115 kV
  - *Limiting Contingency* – Lincoln – Midway 230 kV
- Lamar Injection site, 25 MW
  - Limiting Element - Willow Creek – Lamar 115 kV
  - *Limiting Contingency* – Lamar – Boone 230 kV

While there is some latent capacity in the Burlington system today, specifically 25 MW at Burlington and 75 MW at Wray, the retirements of Hayden U1 and U2 and Comanche U1 and U2 along with the assumed re-dispatch of their generation towards eastern Colorado in the REPTF 2031 Heavy Summer case has created transmission congestion centered around Pawnee and Story Substations. When the Burlington area generation is stressed, this congestion causes the underlying 115 kV system to become more heavily loaded resulting in overloads that appear sooner.

9.0 ALTERNATIVES

The REPTF considered proposals from several stakeholders which would add transmission in southeast and eastern Colorado to facilitate the addition of new resources, improve transmission system reliability, and increase connectivity/flexibility of the transmission system. As part of the development and determination of which alternatives warranted technical analysis numerous factors were taken into consideration, including:

- Prior studies,
- Expanded connections to regional transmission,
- Regional congestion,
- Voltage level (Extra High-Voltage vs Ultra High-Voltage)
- High Voltage Direct Current
- Existing transmission corridors, and
- Operational/maintenance requirements.

The REPTF agreed on which proposed alternatives warranted technical analysis and those that did not. Fifteen (15) total alternatives were studied and are listed below.

Alternatives

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

[10] “ComWal is a placeholder station name for study purposes. Any potential filing with the Commission would include a proposed facility name.

4. Pawnee – Story – Burlington – Lamar 345 kV line; Boone – ComWal 230 kV line

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

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

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

7. Story – Burlington 345 kV line; Burlington – Lamar 230 kV line; Boone – ComWal 230 kV line

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

9. Pawnee – Story – Cheyenne Ridge – Lamar 345 kV line; Boone– ComWal 230 kV line

10. Pawnee – Story – Cheyenne Ridge – Lamar – Tundra 345 kV line; Boone – ComWal 230 kV line

11. Rebuild Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV line; Story/Henry Lake ("StoHen" [11]) – Big Sandy – Boone – ComWal 230 kV line

12. Rebuild Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV line; Story – Big Sandy – Boone – ComWal 230 kV line

13. Rebuild Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV line; Story – Big Sandy 230 kV line; Boone – ComWal 230 kV line

14. Rebuild Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV line; Story – Big Sandy 230 kV line; Burlington – Lamar 230 kV line; Boone – ComWal 230 kV line

For study purposes, the following assumptions were used for components of the proposed alternatives:

- Transmission Line construction
  - 345 kV lines
    - Single circuit, horizontal configuration, bundled 1272kcmil ACSR (Bittern) conductor, rated at 1600 MVA, following existing transmission corridors
  - 230 kV lines
    - Single circuit, horizontal configuration, 1272kcmil ACSR (Bittern) conductor, rated at 478 MVA, following existing transmission corridors
- Transformers

[11] "StoHen is a placeholder station name for study purposes. Any potential filing with the Commission would include a proposed facility name.

- o 345/230kV Transformers rated at 600 MVA

The following alternatives were considered by the REPTF, but were not evaluated though the technical analysis. The reasoning for why each alternative was eliminated as a potential alternative is also discussed.

1. Burlington – Cheyenne Ridge 345 kV line
   a. This alternative is similar to an alternative considered in the Rush Creek Task Force, which explored alternatives to networking the Rush Creek 345 kV Gen Tie line. The Rush Creek Task Force studies showed tying Cheyenne Ridge into Burlington and Lamar without a new 345 kV transmission line towards the Front Range exacerbates existing transmission congestion in the Burlington and Lamar areas while offering minimal new incremental generation injection.
2. HVDC
   a. None of the transmission elements exceeded 140 miles in length, which is well below the estimated breakeven point for HVDC versus traditional high-voltage AC construction. As such, the REPTF agreed that HVDC was not appropriate to be considered in this analysis.
3. Boone – Comanche or Boone – Walsenburg 230 kV line
   a. Extending the line from Boone to Comanche or Walsenburg, rather than sectionalize the existing Comanche – Walsenburg 230 kV line, would result in comparable results at a higher cost. Further, the Comanche substation is a congested location making a new connection challenging.

10.0 COST ESTIMATES

Transmission construction costs have varied greatly in recent years due to significant transmission work occurring in California in responses to wildfires. To objectively create indicative level cost estimates, the REPTF utilized Midcontinent Independent System Operator's ("MISO") Transmission Expansion Plan ("MTEP") 2019 Cost Estimate Guide. This public estimating guide is utilized in MISO planning which covers 15 states across the United States. The MTEP Cost Estimate Guide includes exploratory cost estimates which are useful in developing high-level cost estimates for projects like those under study in the REPTF with low levels of scope definition. The estimates focused on transmission line mileage costs and did not include new interconnection stations or expansions to existing stations. Due to the line length of the alternatives, it was assumed the station costs were negligible compared to the overall transmission line cost. The indicative cost estimates include all applicable labor and overheads associated with the siting support, engineering, design, construction of the facilities, contingency, and AFUDC, and have *no assigned level of accuracy*.

The indicative costs utilized in this analysis from the MTEP Cost Estimate Guide are as follows:

- 345 kV single-circuit transmission line – $2.8M/mile
- 230 kV single-circuit transmission line (new or rebuild/uprate) – $1.7M/mile

Indicative cost estimates were developed for each of the alternatives included in this analysis purely for *comparative purposes*. The indicative cost estimates include only the transmission components associated with the alternative under study. The indicative cost estimates do not include cost estimates to mitigate thermal overloads observed on limiting elements in the analysis to achieve higher levels of generation injection.

The REPTF stresses that the costs contained in this report are not detailed engineering-level estimates for budgetary or resource planning purposes. The estimates are assumed to be Class 5 – MISO's exploratory cost estimates which generally align with the AACE (formerly the Association for the Advancement of Cost Engineering) International Class 5 concept screening estimates. If any particular transmission alternative were to be pursued, detailed engineering-level cost estimates would be developed factoring in final substation configurations, structure design, line routing, and reactive support needs, among other factors.

11.0 POWER FLOW RESULTS

For each alternative, the first ~500 MW of generation injection was scheduled to serve load in Colorado, while the remaining generation injection was scheduled out of the state. Injection sites were modeled as either 400 MW, 800 MW, or 1500 MW generators, depending the alternative studied. Generation was adjusted as follows:

- Heavy Summer Case
    - First ~500 MW of generation injection, generation reduced at:
        - Western Colorado
    - Remainder of generation injection, generation reduced at:
        - Pacific Northwest hydroelectric generation on the lower Columbia River

Generation injection was modeled connected to a simplified collector system on the 34.5 kV bus at the identified substation in the "Study Results" section of each alternatives. The generation injection was modeled assuming 0.95 lead/lag VAR capability. Contingency analysis was performed at varying generation injection levels, in 40 MW, 80 MW, or 150 MW increments (depending if the injection generator was modeled as 400 MW, 800 MW, or 1500 MW, respectively). Limiting elements were noted at the generation injection levels they appeared.

11.1 Alternative 1 Analysis

A. Description

The REPTF discussed DLR and potential to increase line ratings and accommodate additional resources. It was determined that while some lines could realize higher real-time ratings under ideal weather conditions, some transmission constraints are limited by substation terminal equipment (i.e. bus, jumper, switches, etc.), rather the line conductor, preventing the benefit of increased conductor ratings. Further, DLR did not replace the need for additional transmission to provide connectivity or solve reliability concerns under prior outage conditions. The REPTF generally agreed that DLR is an operational tool, rather than a transmission planning input.

The REPTF discussed topology optimization in detail in eastern Colorado. Due to the nature of the existing transmission system, which includes a single 230 kV transmission loop/line and underlying 115 kV system, the creation of normally open points on the 115 kV system reduces system reliability to existing load in rural Colorado and does not materially increase generation injection capability. The REPTF agreed that topology optimization is more appropriate in a more robust transmission system and, as such, it is not appropriate in eastern Colorado at this time.

Alternative 1, shown in Figure 2, added ATT power-flow control ("PFC") technologies to various transmission lines in the benchmark case. It assumes PFC's were added to the following lines for the follow injection locations:

1. Story Injection
   a. Big Sandy – Last Chance 115 kV, +25% line compensation
   b. Burlington – South Fork 115 kV, -25% line compensation
2. Wray Injection
   a. Big Sandy – Last Chance 115 kV, +25% line compensation
   b. Burlington – South Fork 115 kV, -25% line compensation
3. Burlington Injection
   a. Big Sandy – Last Chance 115 kV, +25% line compensation
   b. Burlington – South Fork 115 kV, -25% line compensation
4. Lamar Injection
   a. Lamar – Vilas 115 kV, +25% line compensation

Other types of PFC technologies, such as phase shifting transformers, would result in comparable impacts on system flows and, as a result, were not explicitly studied. No voltage concerns were observed in the analysis, therefore no ATT's involving voltage support/depression, such as FACTS (shunt compensation), were performed due to the lack of an identified need for this technology.

Energy storage was discussed, and it was acknowledged that energy storage does have unique capabilities to enhance the existing system with load management, voltage support, and storage of excess resources. However, energy storage does not replace the need for transmission expansion and connectivity, therefore it was not studied further.

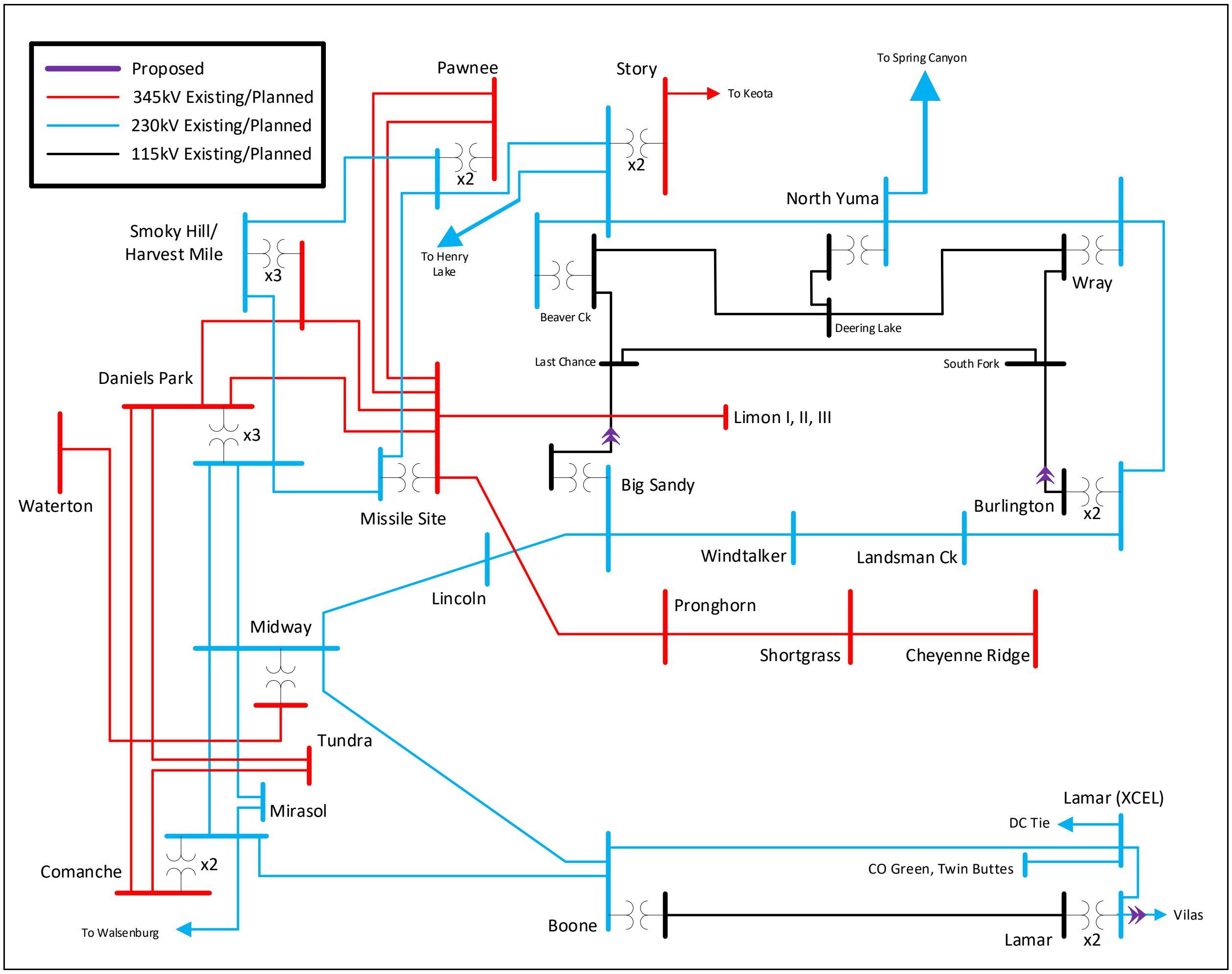

Figure 2: Alternative 1

B. Study Results

Generation was individually injected into the following locations:

1. Story, 400 MW
2. Wray, 400 MW
3. Burlington, 400 MW
4. Lamar, 400 MW

Table 1: Story, 400 MW Injection

Element	Contingency	Generation Accommodated
Smoky Hill – Missile Site 345	Missile Site – Daniels Park 345	0 MW

Table 2: Wray, 400 MW Injection

Element	Contingency	Generation Accommodated
Big Sandy – Woodrow – Beaver Creek 115	Lincoln – Midway 230	50 MW

Table 3: Burlington, 400 MW Injection

Element	Contingency	Generation Accommodated
Big Sandy – Woodrow – Beaver Creek 115	Lincoln – Midway 230	40 MW

Table 4: Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Vilas 115/69 kV	Willow Creek – Lamar 115	25 MW

C. Summary

Alternative 1 is able to meet two of the four identified needs. Specifically, Alternative 1:

- Adjusts transmission flows in eastern Colorado, thereby reducing generation curtailment in eastern Colorado under prior outage conditions.
- Adjusts transmission flows in southeastern Colorado, slightly improving reliability in the Lamar area.

Alternative 1 PFC technology accommodated increased injection capability of 50 MW at Wray, 40 MW at Burlington, or 25 MW at Lamar prior to system constraints. Alternative 1, by itself, does not accommodate the needed 400 MW minimum on new generation in eastern Colorado. Further, Alternative 1 did not include any additional transmission to provide connectivity between Tri-State's four state service area.

Alternative 1 does not appear to be a reasonable alternative to meeting the identified needs of the study.

11.2 Alternative 2 Analysis

A. Description

Alternative 2, shown in Figure 3, constructs a new Story – Burlington – Lamar 230 kV line and a new Boone – ComWal 230 kV line. It assumes the following transmission components:

1. Burlington Satellite 230 kV Substation (New)
    a. Story – Burlington Satellite 230 kV
    b. Lamar – Burlington Satellite 230 kV
    c. Landsman Creek – Burlington Satellite 230 kV
    d. Burlington – Burlington Satellite 230 kV #1
    e. Burlington – Burlington Satellite 230 kV #2 (Optional) [12]
2. ComWal 230 kV Substation (New)
    a. Boone – ComWal 230 kV
    b. Comanche – ComWal 230 kV
    c. Walsenburg – ComWal 230 kV

Alternative 2 would consist of approximately 250 miles of new 230 kV transmission. The planning level estimate using the MISO exploratory costs totals approximately $425 million.

[12] The Burlington – Burlington Satellite 230 kV line #1 is currently designed for 50 deg C operation (690 A, 274 MVA). Line #1 would require modifications to allow 100 deg C operation (1338 A, 533 MVA) to mitigate constraints between Burlington and the Burlington Satellite yards. A second circuit (Line #2) may be needed to maintain the connection between the Burlington and Burlington Satellite yards under contingency conditions.

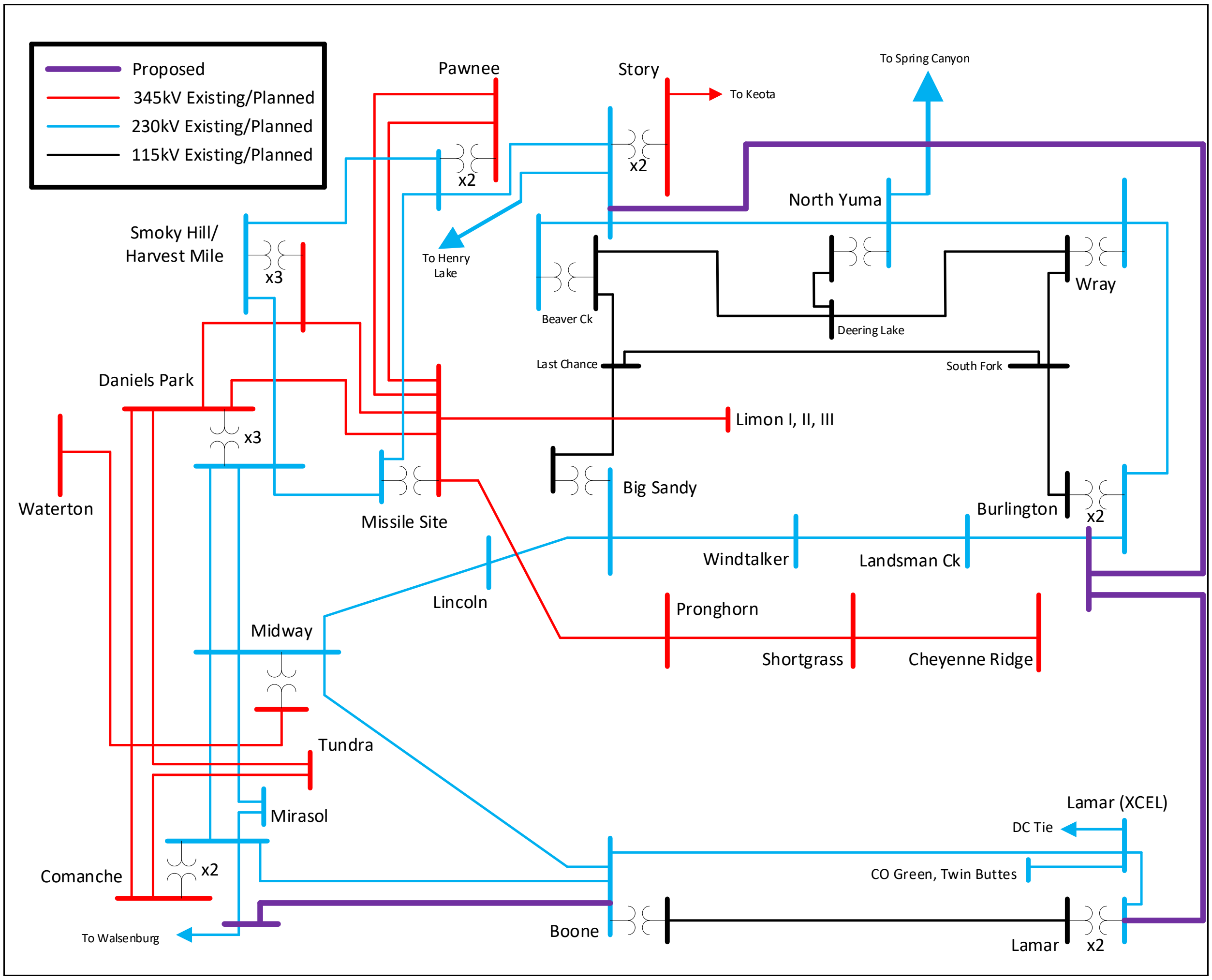

Figure 3: Alternative 2

B. Study Results

Generation was individually injected into the following locations:

1. Story, 400 MW
2. Burlington, 400 MW
3. Lamar, 400 MW
4. Burlington, 400 MW & Lamar, 400 MW

Table 5: Story, 400 MW Injection

Element	Contingency	Generation Accommodated
Smoky Hill – Missile Site 345	Missile Site – Daniels Park 345	0 MW

Table 6: Burlington, 400 MW Injection

Element	Contingency	Generation Accommodated
Big Sandy – L. Chance – Woodrow – Beaver Ck 115	Lincoln – Midway 230	360 MW
Deering Lake – E. Yuma – Eckley 115	Wray – N. Yuma 230	360 MW

Table 7: Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Vilas 115/69 T1	Willow Creek – Lamar 115	200 MW
Lamar – Willow Creek 115	Lamar – Burlington Satellite 230	280 MW
Boone – Lamar 230	Lamar – Burlington Satellite 230	320 MW
--- Non Converged ---	Lamar – Burlington Satellite 230	>360 MW

Table 8: Burlington, 400 MW Injection & Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Vilas 115/69 T1	Willow Creek – Lamar 115	280 MW
Big Sandy – L. Chance – Woodrow – Beaver Ck 115	Lincoln – Midway 230	480 MW
Deering Lake – E. Yuma – Eckley 115	Wray – N. Yuma 230	480 MW

C. Summary

Alternative 2 is able to meet three of the four identified needs. Specifically, Alternative 2:

- Provides new transmission into the Lamar area with the Burlington Satellite – Lamar 230 kV line, thereby significantly improving system reliability.
- Provides connectivity across Tri-State's four state service area with the Boone – ComWal 230 kV line.
- Provides new transmission into the Burlington area with the Story – Burlington Satellite – Lamar 230 kV line, thereby reducing generation curtailment in eastern Colorado under prior outage conditions.

Alternative 2 accommodated increased injection capability of 360 MW at Burlington, 200 MW at Lamar, or 280 MW split evenly between Burlington and Lamar prior to system constraints. Network upgrades could be constructed to further increase injection capability to higher levels. However the primary limiting element to accommodate at least 400 MW of new generation is WAPA's Big Sandy – Last Chance – … – Beaver Ck 115kV line, which is conductor limited and approximately 66 miles in length. To remove the limitation, the WAPA line would require a full rebuild, or a new parallel transmission circuit. Alternative 2, by itself, does not accommodate the needed 400 MW minimum on new generation in eastern Colorado.

Alternative 2 does not appear to be a reasonable alternative to meeting the identified needs of the study.

11.3 Alternative 3 Analysis

A. Description

Alternative 3, shown in Figure 4, constructs a new Story – Burlington – Lamar 345 kV line and a new Boone – ComWal 230 kV line. It assumes the following transmission components:

1. Burlington Satellite 345/230 kV Substation (New)
    a. Story – Burlington Satellite 345 kV
    b. Lamar – Burlington Satellite 345 kV
    c. Landsman Creek – Burlington Satellite 230 kV
    d. Burlington – Burlington Satellite 230 kV
    e. Two (2) 345/230 kV 400MVA transformers
2. Lamar 345/230 kV Substation (Substation Expansion)
    a. Lamar – Burlington Satellite 345 kV
    b. Two (2) 345/230 kV 400MVA transformers
3. ComWal 230 kV Substation (New)
    a. Boone – ComWal 230 kV
    b. Comanche – ComWal 230 kV
    c. Walsenburg – ComWal 230 kV

Alternative 3 would consist of approximately 215 miles of new 345 kV transmission and 35 miles of new 230 kV transmission. The planning level estimate using the MISO exploratory costs totals approximately $661.5 million.

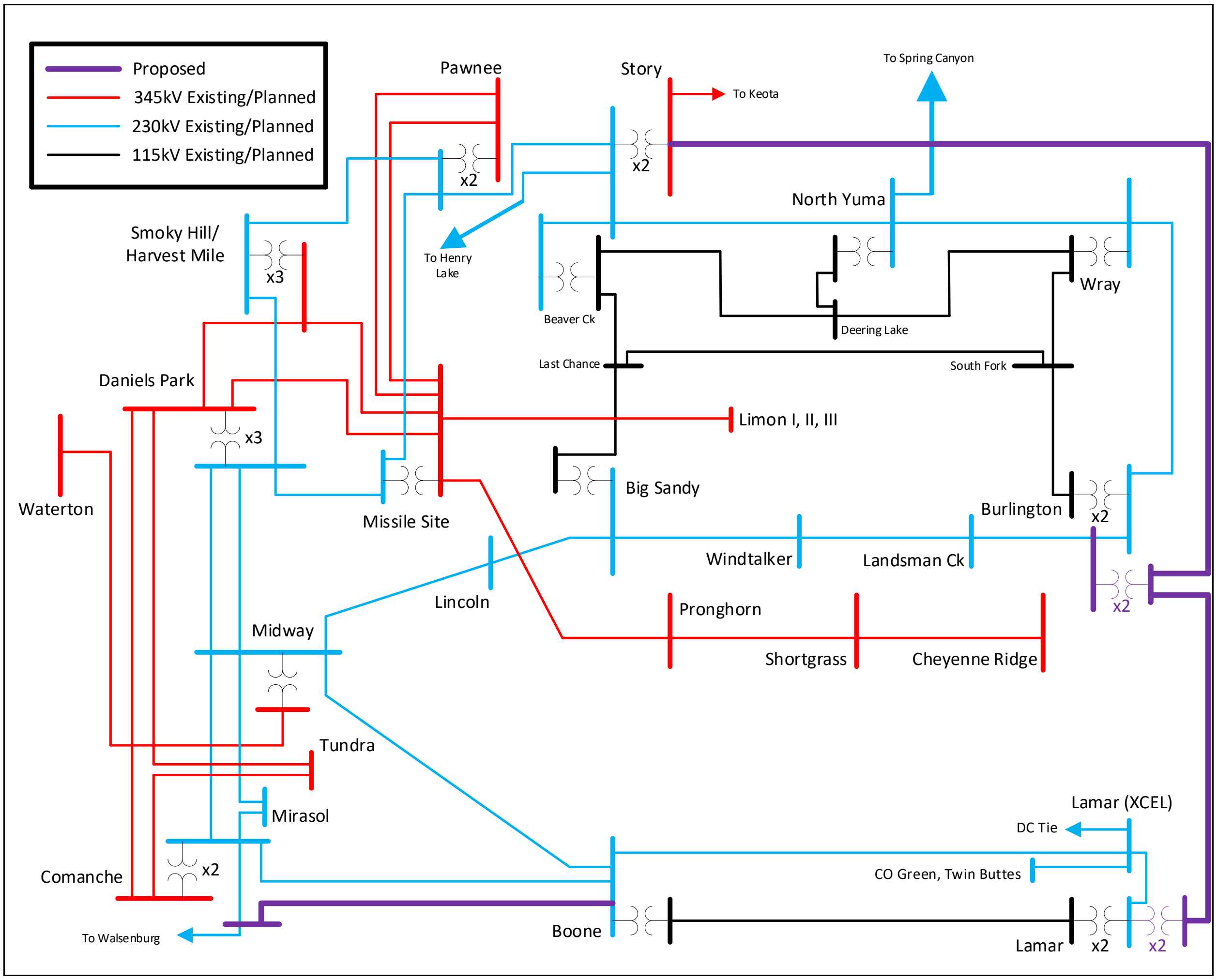

Figure 4: Alternative 3

B. Study Results

Generation was individually injected into the following locations:

1. Story, 400 MW
2. Burlington, 800 MW
3. Lamar, 400 MW
4. Burlington, 400 MW & Lamar, 400 MW

Table 9: Story, 400 MW Injection

Element	Contingency	Generation Accommodated
Smoky Hill – Missile Site 345	Missile Site – Daniels Park 345	0 MW

Table 10: Burlington, 800 MW Injection

Element	Contingency	Generation Accommodated
Big Sandy – Windtalker 230	Story – Burlington Satellite 345	560 MW
N. Yuma – Story 230	Story – Burlington Satellite 345	640 MW
Burlington – Bonny Creek – South Fork 115	Story – Burlington Satellite 345	640 MW
Burlington – Burlington Satellite 230	Story – Burlington Satellite 345	720 MW

Table 11: Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Lamar – Willow Creek 115	Lamar – Burlington Satellite 345	280 MW
Boone – Lamar 230	Lamar – Burlington Satellite 345	320 MW
--- Non Converged ---	Lamar – Burlington Satellite 345	>360 MW

Table 12: Burlington, 400 MW Injection & Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Lamar – Willow Creek 115	Lamar – Burlington Satellite 345	560 MW
Vilas 115/69 T1	Willow Creek – Lamar 115	560 MW
Boone – Lamar 230	Lamar – Burlington Satellite 345	640 MW
Big Sandy – Windtalker 230	Story – Burlington Satellite 345	640 MW
Burlington – Bonny Creek – South Fork 115	Story – Burlington Satellite 345	720 MW
N. Yuma – Story 230	Story – Burlington Satellite 345	720 MW
--- Non Converged ---	Lamar – Burlington Satellite 345	720 MW

C. Summary

Alternative 3 is able to meet all four of the identified needs. Specifically, Alternative 3:

- Provides new transmission to accommodate at least 400 MW of new generation in eastern Colorado
- Provides new transmission into the Lamar area with the Burlington Satellite – Lamar 345 kV line, thereby significantly improving system reliability.
- Provides connectivity across Tri-State's four state service area with the Boone – ComWal 230 kV line.
- Provides new transmission into the Burlington area with the Story – Burlington Satellite – Lamar 345 kV line, thereby reducing generation curtailment in eastern Colorado under prior outage conditions.

Alternative 3 accommodated increased injection capability of 560 MW at Burlington, 280 MW at Lamar, or 560 MW split evenly between Burlington and Lamar prior to system constraints. Network upgrades could be constructed to further increase injection capability to higher levels. The transmission lines limiting Burlington injection are all older, conductor limited lines designed for operation below current design standards (100 deg C operation). Structure modifications and/or replacements could occur on any of these lines to allow 100 deg C operation, rather than a full rebuild, to increase injection capability at a reduced cost when compared to a new line or full line rebuild.

Alternative 3 appears to be a reasonable alternative to meeting the identified needs of the study while providing room for additional resource development and growth.

11.4 Alternative 4 Analysis

A. Description

Alternative 4, shown in Figure 5, constructs a new Pawnee – Story – Burlington – Lamar 345 kV line and a new Boone – ComWal 230 kV line. It assumes the following transmission components:

1. Pawnee – Story 345 kV
2. Burlington Satellite 345/230 kV Substation (New)
    a. Story – Burlington Satellite 345 kV
    b. Lamar – Burlington Satellite 345 kV
    c. Landsman Creek – Burlington Satellite 230 kV
    d. Burlington – Burlington Satellite 230 kV
    e. Two (2) 345/230 kV 400MVA transformers
3. Lamar 345/230 kV Substation (Substation Expansion)
    a. Lamar – Burlington Satellite 345 kV
    b. Two (2) 345/230 kV 400MVA transformers
4. ComWal 230 kV Substation (New)
    a. Boone – ComWal 230 kV
    b. Comanche – ComWal 230 kV
    c. Walsenburg – ComWal 230 kV

Alternative 4 would consist of approximately 225 miles of new 345 kV transmission and 35 miles of new 230 kV transmission. The planning level estimate using the MISO exploratory costs totals approximately $689.5 million.

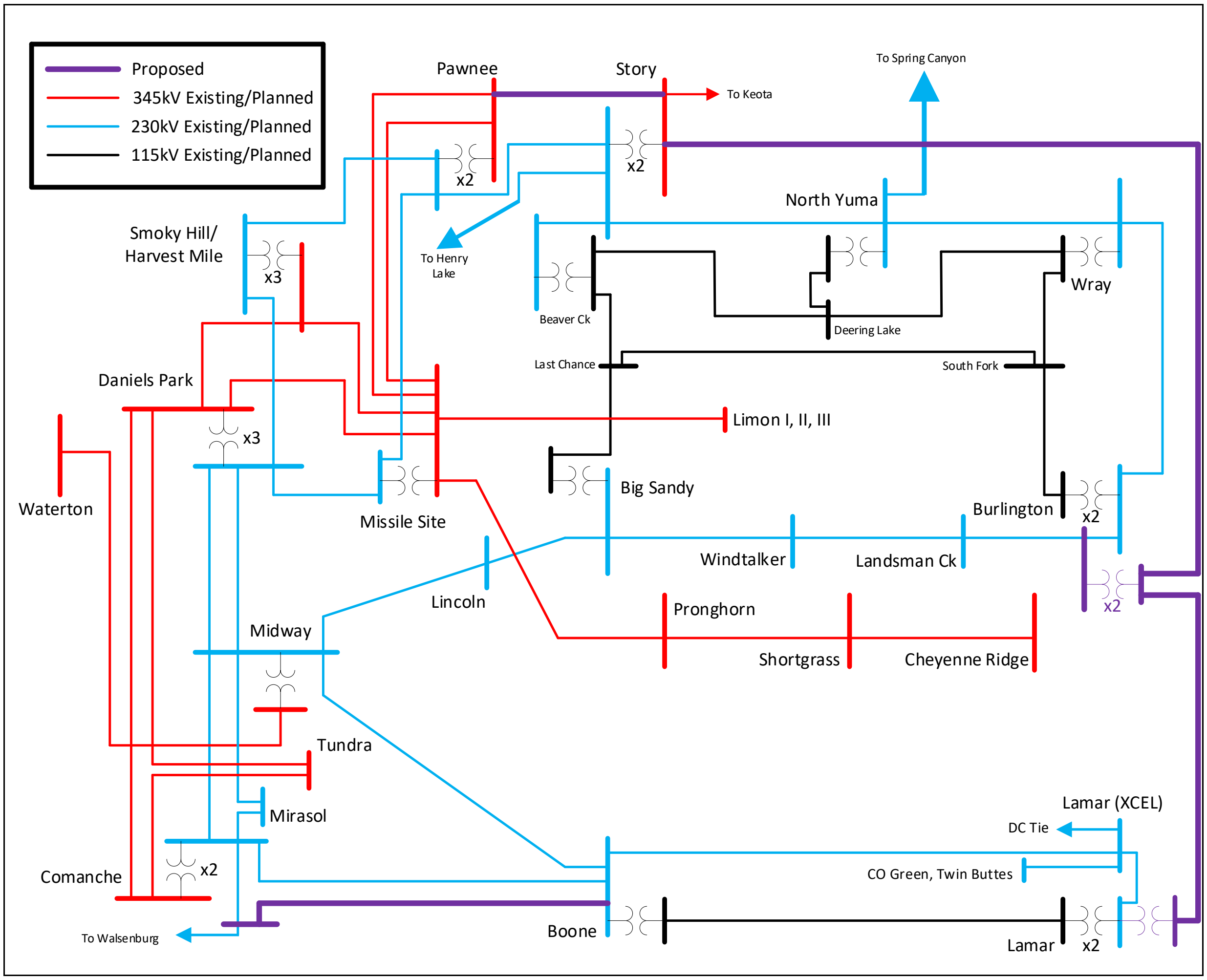

Figure 5: Alternative 4

B. Study Results

Generation was individually injected into the following locations:

1. Story, 400 MW
2. Burlington, 800 MW
3. Lamar, 400 MW
4. Burlington, 400 MW & Lamar, 400 MW

Table 13: Story, 400 MW Injection

Element	Contingency	Generation Accommodated
Smoky Hill – Missile Site 345	Missile Site – Daniels Park 345	0 MW

Table 14: Burlington, 800 MW Injection

Element	Contingency	Generation Accommodated
Big Sandy – Windtalker 230	Story – Burlington Satellite 345	560 MW
N. Yuma – Story 230	Story – Burlington Satellite 345	640 MW
Burlington – Bonny Creek – South Fork 115	Story – Burlington Satellite 345	640 MW
Burlington – Burlington Satellite 230	Story – Burlington Satellite 345	720 MW

Table 15: Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Lamar – Willow Creek 115	Lamar – Burlington Satellite 345	280 MW
Boone – Lamar 230	Lamar – Burlington Satellite 345	320 MW
--- Non Converged ---	Lamar – Burlington Satellite 345	>360 MW

Table 16: Burlington, 400 MW Injection & Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Lamar – Willow Creek 115	Lamar – Burlington Satellite 345	560 MW
Vilas 115/69 T1	Willow Creek – Lamar 115	640 MW
Boone – Lamar 230	Lamar – Burlington Satellite 345	640 MW
Big Sandy – Windtalker 230	Story – Burlington Satellite 345	640 MW
Burlington – Bonny Creek – South Fork 115	Story – Burlington Satellite 345	720 MW
N. Yuma – Story 230	Story – Burlington Satellite 345	720 MW
--- Non Converged ---	Lamar – Burlington Satellite 345	720 MW

C. Summary

Alternative 4 is able to meet all four of the identified needs. Specifically, Alternative 4:

- Provides new transmission to accommodate at least 400 MW of new generation in eastern Colorado
- Provides new transmission into the Lamar area with the Burlington Satellite – Lamar 345 kV line, thereby significantly improving system reliability.
- Provides connectivity across Tri-State's four state service area with the Boone – ComWal 230 kV line.
- Provides new transmission into the Burlington area with the Story – Burlington Satellite – Lamar 345 kV line, thereby reducing generation curtailment in eastern Colorado under prior outage conditions.

Alternative 4 accommodated increased injection capability of 560 MW at Burlington, 280 MW at Lamar, or 560 MW split evenly between Burlington and Lamar prior to system constraints. Network upgrades could be constructed to further increase injection capability to higher levels. The transmission lines limiting Burlington injection are all older, conductor limited lines designed for operation below current design standards (100 deg C operation). Structure modifications and/or replacements could occur on any of these lines to allow 100 deg C operation, rather than a full rebuild, to increase injection capability at a reduced cost when compared to a new line or full line rebuild. Alternative 4 demonstrated near identical results to Alternative 3, demonstrating the addition of the Pawnee – Story 345 kV does not assist in meeting any of the identified needs or materially improve injection capability in eastern Colorado.

Alternative 4 appears to be a reasonable alternative to meeting the identified needs of the study while providing room for additional resource development, although at a higher cost that Alternative 3. A new connection between Pawnee and Story Substations may provide other benefits, but none were identified through this analysis.

11.5 Alternative 5 Analysis

A. Description

Alternative 5, shown in Figure 6, constructs a new Pawnee – Story – Burlington – Lamar 345 kV line, a new Burlington – Cheyenne Ridge 345 kV line, and a new Boone – ComWal 230 kV line. It assumes the following transmission components:

1. Pawnee – Story 345 kV
2. Burlington Satellite 345/230 kV Substation (New)
   a. Story – Burlington Satellite 345 kV
   b. Lamar – Burlington Satellite 345 kV
   c. Cheyenne Ridge – Burlington Satellite 345 kV
   d. Landsman Creek – Burlington Satellite 230 kV
   e. Burlington – Burlington Satellite 230 kV
   f. Two (2) 345/230 kV 400MVA transformers
3. Lamar 345/230 kV Substation (Substation Expansion)
   a. Two (2) 345/230 kV 400MVA transformers
4. ComWal 230 kV Substation (New)
   a. Boone – ComWal 230 kV
   b. Comanche – ComWal 230 kV
   c. Walsenburg – ComWal 230 kV

Alternative 5 would consist of approximately 245 miles of new 345 kV transmission and 35 miles of new 230 kV transmission. The planning level estimate using the MISO exploratory costs totals approximately $745.5 million.

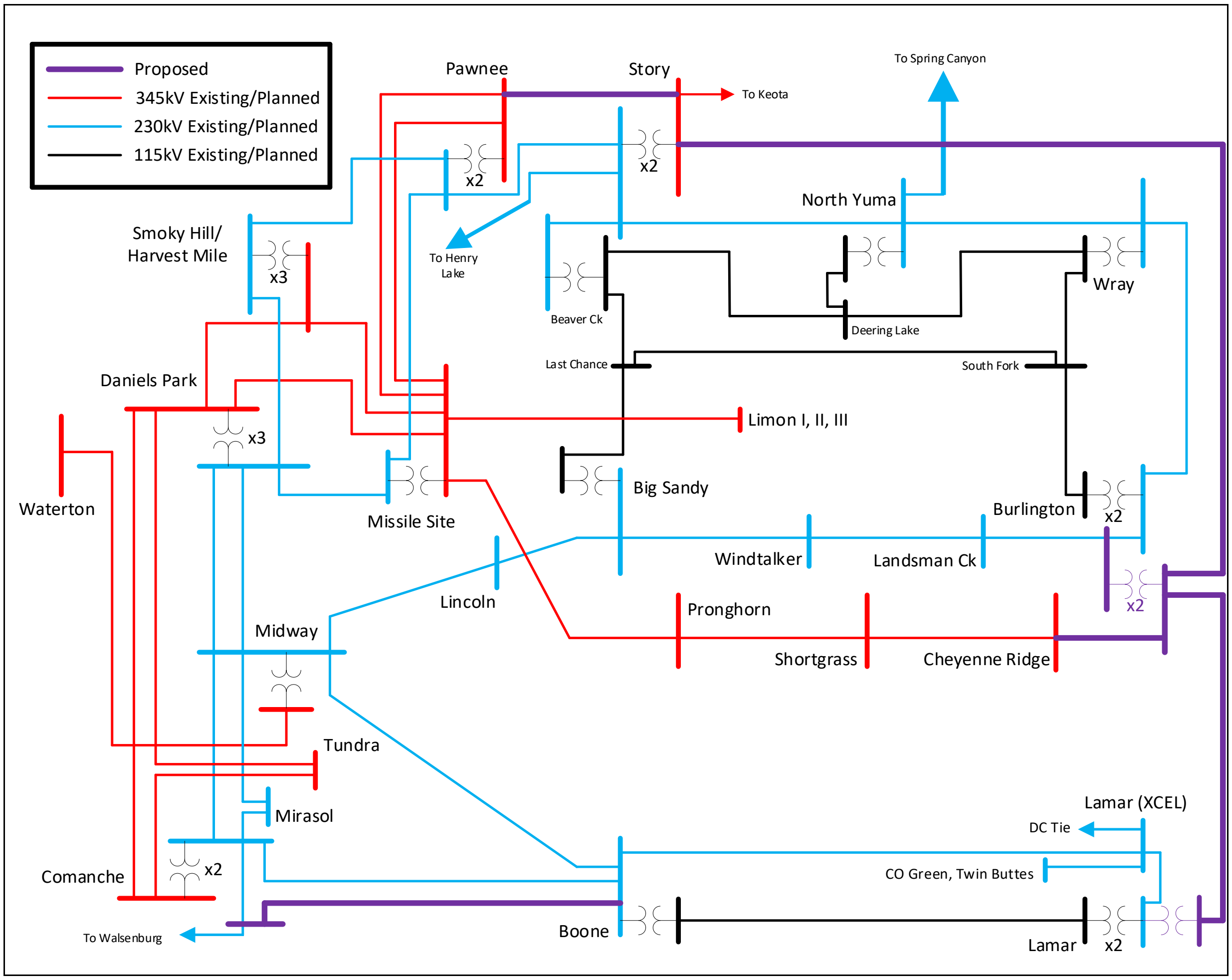

Figure 6: Alternative 5

B. Study Results

Generation was individually injected into the following locations:

1. Story, 400 MW
2. Burlington, 800 MW
3. Lamar, 400 MW
4. Burlington, 400 MW & Lamar, 400 MW

Table 17: Story, 400 MW Injection

Element	Contingency	Generation Accommodated
Smoky Hill – Missile Site 345	Missile Site – Daniels Park 345	80 MW

Table 18: Burlington, 800 MW Injection

Element	Contingency	Generation Accommodated
Big Sandy – Windtalker 230	Missile Site - Pronghorn 345	400 MW
Missile Site – Smoky Hill 345	Missile Site – Daniels Park 345	640 MW
Burlington – Bonny Creek – South Fork 115	Missile Site - Pronghorn 345	640 MW
Lamar – Willow Creek 115	Missile Site - Pronghorn 345	640 MW
Burlington – Burlington Satellite 230	Missile Site - Pronghorn 345	720 MW

Table 19: Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Lamar – Willow Creek 115	Lamar – Burlington Satellite 345	320 MW
Boone – Lamar 230	Lamar – Burlington Satellite 345	320 MW
Vilas 115/69 T1	Willow Creek – Lamar 115	320 MW
--- Non Converged ---	Lamar – Burlington Satellite 345	>400 MW

Table 20: Burlington, 400 MW Injection & Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Big Sandy – Windtalker 230	Missile Site - Pronghorn 345	480 MW
Vilas 115/69 T1	Willow Creek – Lamar 115	480 MW
Lamar – Willow Creek 115	Lamar – Burlington Satellite 345	560 MW
Boone – Lamar 230	Lamar – Burlington Satellite 345	640 MW
Burlington – Bonny Creek – South Fork 115	Story – Burlington Satellite 345	720 MW
--- Non Converged ---	Lamar – Burlington Satellite 345	720 MW

C. Summary

Alternative 5 is able to meet all four of the identified needs. Specifically, Alternative 5:

- Provides new transmission to accommodate at least 400 MW of new generation in eastern Colorado
- Provides new transmission into the Lamar area with the Burlington Satellite – Lamar 345 kV line, thereby significantly improving system reliability.
- Provides connectivity across Tri-State's four state service area with the Boone – ComWal 230 kV line.
- Provides new transmission into the Burlington area with the Story – Burlington Satellite – Lamar 345 kV line, thereby reducing generation curtailment in eastern Colorado under prior outage conditions.

Alternative 5 accommodated increased injection capability of 80 MW at Story, 400 MW at Burlington, 320 MW at Lamar, or 480 MW split evenly between

Burlington and Lamar prior to system constraints. Network upgrades could be constructed to further increase injection capability to higher levels. Alternative 5 demonstrated reduced increases in injection capability in comparison to Alternatives 3 and 4. The reduced benefit can be attributed to networking the Rush Creek Gen-Tie, specifically Cheyenne Ridge, at Burlington. Consistent with observations in the CCPG Rush Creek Task Force and the Lamar Front Range Task Force, networking the Rush Creek Gen-Tie requires the transmission system to accommodate up to 1400 MW of existing generation on the Rush Creek Gen-Tie. For the loss of Missile Site – Pronghorn 345 kV, existing generation on the Rush Creek Gen-Tie is injected into Burlington, thereby utilizing some of the incremental increase in injection capability created by the transmission built out of Burlington.

Alternative 5 appears to be a less reasonable alternative to meeting the identified needs of the study due to the higher cost than Alternatives 3 and 4, at a reduced injection capability.

11.6 Alternative 6 Analysis

A. Description

Alternative 6, shown in Figure 7, constructs a new Pawnee – Story – Burlington – Lamar – Tundra 345 kV line, a new Burlington – Cheyenne Ridge 345 kV line, and a new Boone – ComWal 230 kV line. It assumes the following transmission components:

1. Pawnee – Story 345 kV
2. Burlington Satellite 345/230 kV Substation (New)
    a. Story – Burlington Satellite 345 kV
    b. Lamar – Burlington Satellite 345 kV
    c. Cheyenne Ridge – Burlington Satellite 345 kV
    d. Landsman Creek – Burlington Satellite 230 kV
    e. Burlington – Burlington Satellite 230 kV
    f. Two (2) 345/230 kV 400MVA transformers
3. Lamar 345/230 kV Substation (Substation Expansion)
    a. Lamar – Tundra 345 kV
    b. Two (2) 345/230 kV 400MVA transformers
4. ComWal 230 kV Substation (New)
    a. Boone – ComWal 230 kV
    b. Comanche – ComWal 230 kV
    c. Walsenburg – ComWal 230 kV

Alternative 6 would consist of approximately 370 miles of new 345 kV transmission and 35 miles of new 230 kV transmission. The planning level estimate using the MISO exploratory costs totals approximately $1.095 billion.

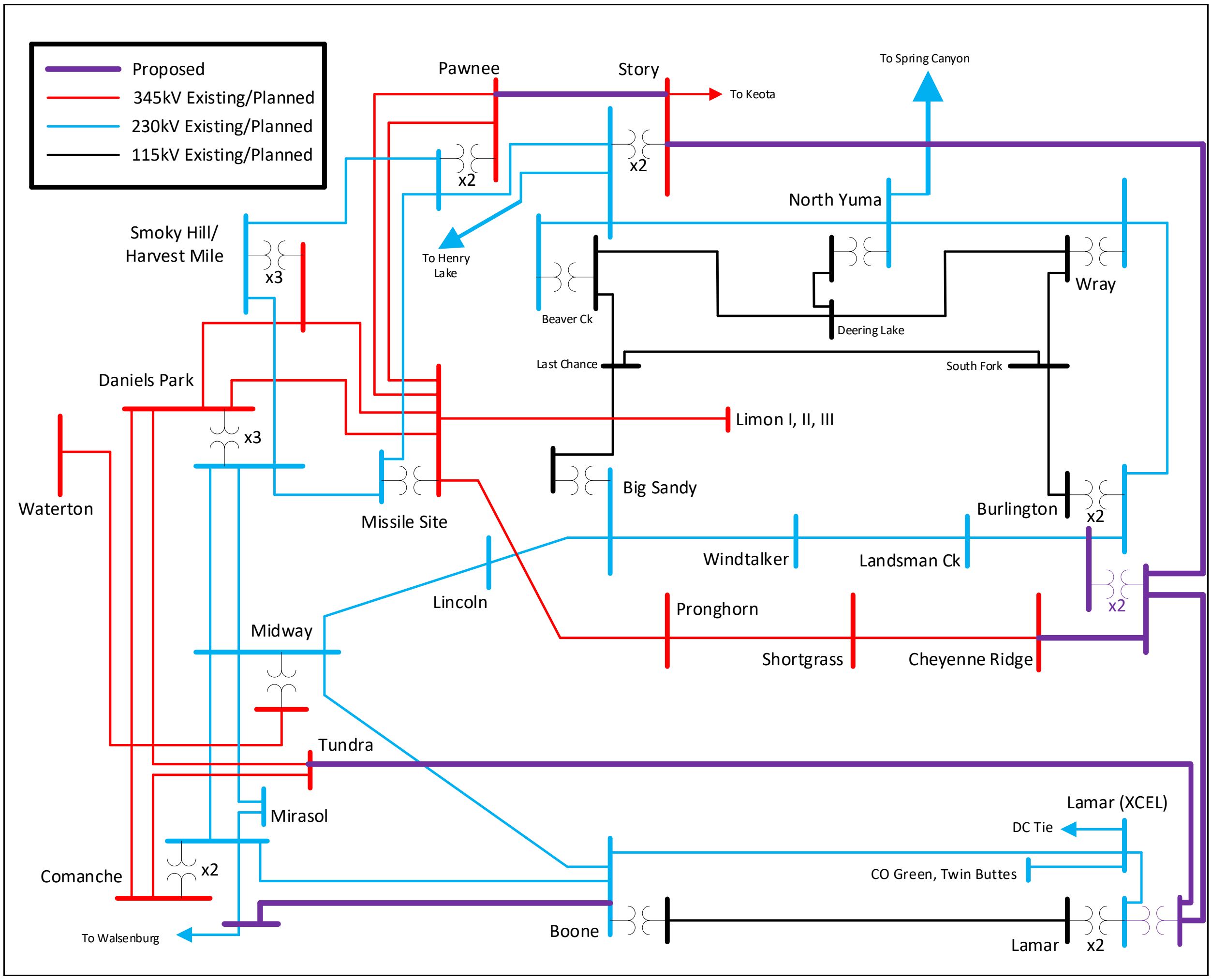

Figure 7: Alternative 6

B. Study Results

Generation was individually injected into the following locations:

1. Story, 800 MW
2. Burlington, 1500 MW
3. Lamar, 1500 MW
4. Burlington, 800 MW & Lamar, 800 MW

Table 21: Story, 800 MW Injection

Element	Contingency	Generation Accommodated
Smoky Hill – Missile Site 345	Missile Site – Daniels Park 345	560 MW

Table 22: Burlington, 1500 MW Injection

Element	Contingency	Generation Accommodated
Big Sandy – Windtalker 230	Missile Site – Pronghorn 345	900 MW

Table 23: Lamar, 1500 MW Injection

Element	Contingency	Generation Accommodated
Vilas 115/69 T1	Lamar – Willow Creek 115	1050 MW
Lamar – Willow Creek 115	Lamar – Tundra 345	1050 MW

Table 24: Burlington, 800 MW Injection & Lamar, 800 MW Injection

Element	Contingency	Generation Accommodated
Big Sandy – Windtalker 230	Missile Site – Pronghorn 345	1280 MW
Burlington – Bonny Creek – South Fork 115	Missile Site – Pronghorn 345	1280 MW

C. Summary

Alternative 6 is able to meet all four of the identified needs. Specifically, Alternative 6:

- Provides new transmission to accommodate at least 400 MW of new generation in eastern Colorado
- Provides new transmission into the Lamar area with the Burlington Satellite – Lamar 345 kV line, thereby significantly improving system reliability.
- Provides connectivity across Tri-State's four state service area with the Boone – ComWal 230 kV line.
- Provides new transmission into the Burlington area with the Story – Burlington Satellite – Lamar 345 kV line, thereby reducing generation curtailment in eastern Colorado under prior outage conditions.

Alternative 6 accommodated increased injection capability of 560 MW at Story, 900 MW at Burlington, 1050 MW at Lamar, or 1280 MW split evenly between Burlington and Lamar prior to system constraints. Network upgrades could be constructed to further increase injection capability to higher levels. Alternative 6 demonstrated greater increases in injection capability in comparison to Alternatives 3, 4, and 5. The increase benefit can be attributed to additional 345 kV connection between Lamar and Tundra, creating a third[13] 345 kV path from

[13] The other two paths are the Burlington – Story 345 kV considered in Alternative 6 and the existing Missile Site – Pronghorn – Shortgrass – Cheyenne Ridge 345 kV line (known as the Rush Creek Gen-Tie).

eastern Colorado towards the Front Range. Similar to Alternative 5, for the loss of Missile Site – Pronghorn 345 kV, existing generation on the Rush Creek Gen-Tie is injected into Burlington how the additional transmission path allows for increase injection capability.

Alternative 6 appears to be a reasonable alternative to meeting the identified needs of the study with higher injection capability levels, however at a higher cost than Alternatives 3, 4, and 5.

11.7 Alternative 6B Analysis

A. Description

Alternative 6B, shown in Figure 8, constructs a new Pawnee – Story – Burlington – Lamar 345 kV line, a new Burlington – Cheyenne Ridge 345 kV line, a new Boone – Lamar 230 kV line, and a new Boone – ComWal 230 kV line. It assumes the following transmission components:

1. Pawnee – Story 345 kV
2. Burlington Satellite 345/230 kV Substation (New)
    a. Story – Burlington Satellite 345 kV
    b. Lamar – Burlington Satellite 345 kV
    c. Cheyenne Ridge – Burlington Satellite 345 kV
    d. Landsman Creek – Burlington Satellite 230 kV
    e. Burlington – Burlington Satellite 230 kV
    f. Two (2) 345/230 kV 400MVA transformers
3. Lamar 345/230 kV Substation (Substation Expansion)
    a. Boone – Lamar 230 kV
    b. Two (2) 345/230 kV 400MVA transformers
4. ComWal 230 kV Substation (New)
    a. Boone – ComWal 230 kV
    b. Comanche – ComWal 230 kV
    c. Walsenburg – ComWal 230 kV

Alternative 6B would consist of approximately 245 miles of new 345 kV transmission and 135 miles of new 230 kV transmission. The planning level estimate using the MISO exploratory costs totals approximately $915.5 million.

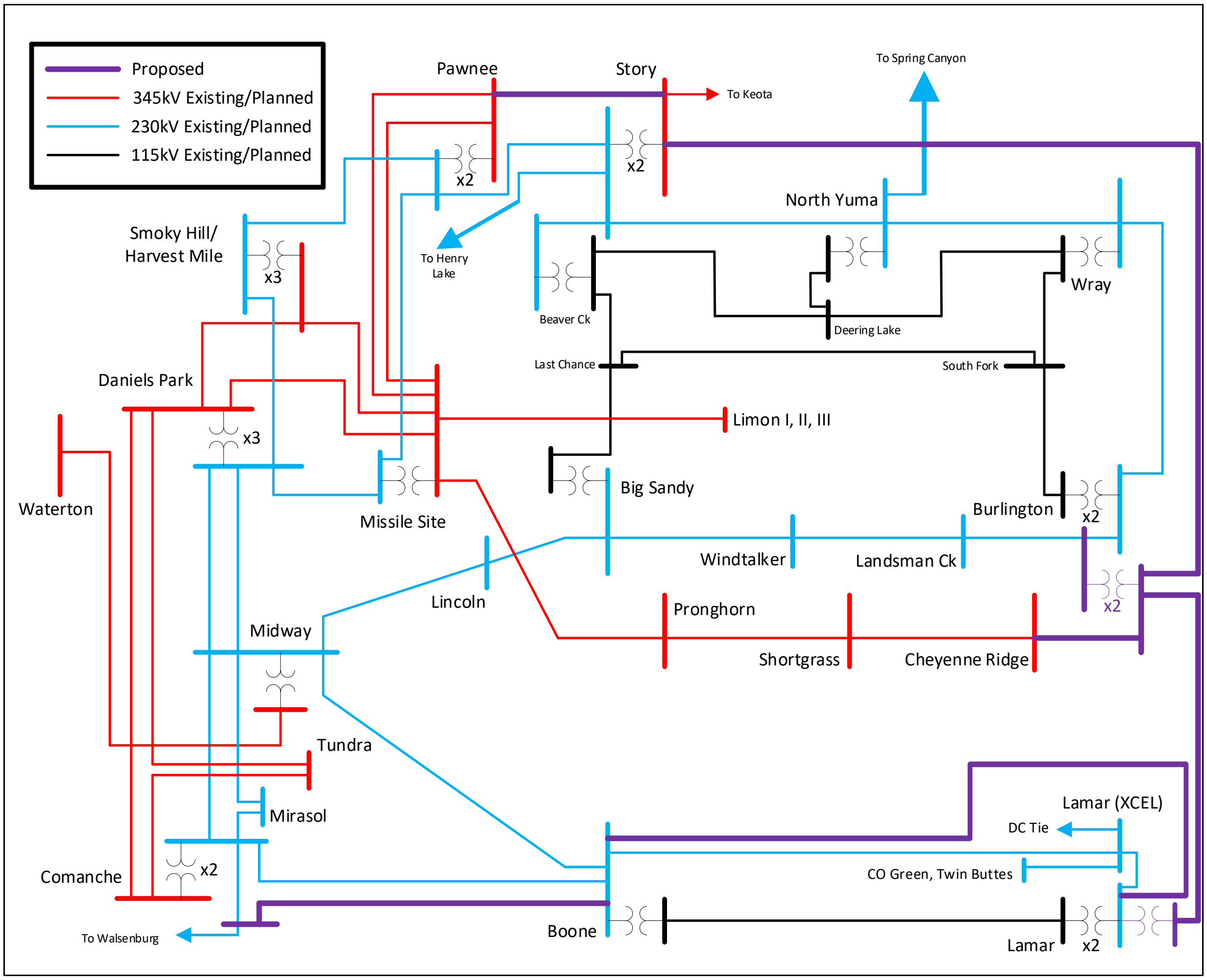

Figure 8: Alternative 6B

B. Study Results

Generation was individually injected into the following locations:

5. Story, 400 MW
6. Burlington, 800 MW
7. Lamar, 800 MW
8. Burlington, 800 MW & Lamar, 800 MW

Table 25: Story, 400 MW Injection

Element	Contingency	Generation Accommodated
Smoky Hill – Missile Site 345	Missile Site – Daniels Park 345	240 MW

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Table 26: Burlington, 800 MW Injection

Element	Contingency	Generation Accommodated
Big Sandy – Windtalker 230	Missile Site – Pronghorn 345	640 MW

Table 27: Lamar, 800 MW Injection

Element	Contingency	Generation Accommodated
Vilas 115/69 T1	Lamar – Willow Creek 115	720 MW

Table 28: Burlington, 800 MW Injection & Lamar, 800 MW Injection

Element	Contingency	Generation Accommodated
Big Sandy – Windtalker 230	Missile Site – Pronghorn 345	800 MW

C. Summary

Alternative 6B is able to meet all four of the identified needs. Specifically, Alternative 6B:

- Provides new transmission to accommodate at least 400 MW of new generation in eastern Colorado
- Provides new transmission into the Lamar area with the Burlington Satellite – Lamar 345 kV line, thereby significantly improving system reliability.
- Provides connectivity across Tri-State's four state service area with the Boone – ComWal 230 kV line.
- Provides new transmission into the Burlington area with the Story – Burlington Satellite – Lamar 345 kV line, thereby reducing generation curtailment in eastern Colorado under prior outage conditions.

Alternative 6B accommodated increased injection capability of 240 MW at Story, 640 MW at Burlington, 720 MW at Lamar, or 800 MW split evenly between Burlington and Lamar prior to system constraints. Network upgrades could be constructed to further increase injection capability to higher levels. Alternative 6B demonstrated greater increases in injection capability in comparison to Alternatives 3, 4, and 5, but a reduction in comparison to Alternative 6. The difference in benefit can be attributed to the 230 kV connection between Lamar and Boone, creating a new path from Lamar towards the Front Range. Similar to Alternative 5, for the loss of Missile Site – Pronghorn 345 kV, existing generation on the Rush Creek Gen-Tie is injected into Burlington how the additional transmission path allows for increase injection capability.

Alternative 6B appears to be a reasonable alternative to meeting the identified needs of the study with higher injection capability levels, however at a higher cost than Alternatives 3, 4, and 5.

11.8 Alternative 7 Analysis

A. Description

Alternative 7, shown in Figure 9, constructs a new Story – Burlington 345 kV line, a new Burlington – Lamar 230 kV line, and a new Boone – ComWal 230 kV line. It assumes the following transmission components:

1. Burlington Satellite 345/230 kV Substation (new)
   a. Story – Burlington Satellite 345 kV
   b. Lamar – Burlington Satellite 230 kV
   c. Landsman Creek – Burlington Satellite 230 kV
   d. Burlington – Burlington Satellite 230 kV
   e. Two (2) 345/230 kV 400MVA transformers
2. ComWal 230 kV Substation
   a. Boone – ComWal 230 kV
   b. Comanche – ComWal 230 kV
   c. Walsenburg – ComWal 230 kV

Alternative 7 would consist of approximately 120 miles of new 345 kV transmission and 130 miles of new 230 kV transmission. The planning level estimate using the MISO exploratory costs totals approximately $557 million.

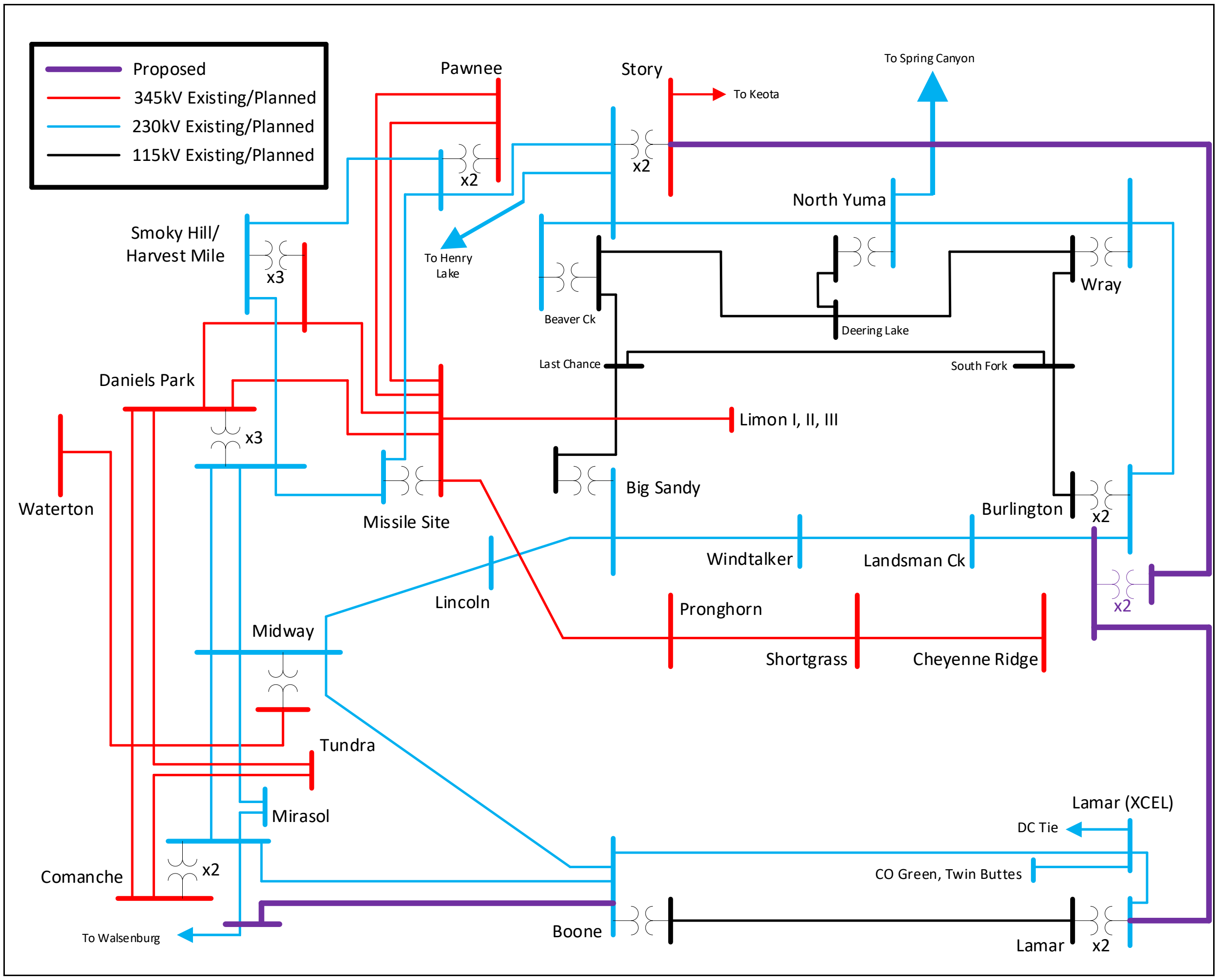

Figure 9: Alternative 7

B. Study Results

Generation was individually injected into the following locations:

1. Story, 400 MW
2. Burlington, 800 MW
3. Lamar, 400 MW
4. Burlington, 400 MW & Lamar, 400 MW

Table 29: Story, 400 MW Injection

Element	Contingency	Generation Accommodated
Smoky Hill – Missile Site 345	Missile Site – Daniels Park 345	0 MW

Table 30: Burlington, 800 MW Injection

Element	Contingency	Generation Accommodated
Big Sandy – Windtalker 230	Story – Burlington Satellite 345	480 MW
Burlington – Bonny Creek – South Fork 115	Story – Burlington Satellite 345	560 MW
N. Yuma – Story 230	Story – Burlington Satellite 345	560 MW
N. Yuma – Wray 230	Story – Burlington Satellite 345	720 MW
Deering Lake – E. Yuma – Eckley 115	Story – Burlington Satellite 345	720 MW

Table 31: Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Vilas 115/69 T1	Willow Creek – Lamar 115	240 MW
Lamar – Willow Creek 115	Lamar – Burlington Satellite 230	280 MW
Boone – Lamar 230	Lamar – Burlington Satellite 230	320 MW
--- Non Converged ---	Lamar – Burlington Satellite 230	>360 MW

Table 32: Burlington, 400 MW Injection & Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Vilas 115/69 T1	Willow Creek – Lamar 115	400 MW
Lamar – Willow Creek 115	Lamar – Burlington Satellite 230	560 MW
Boone – Lamar 230	Lamar – Burlington Satellite 230	640 MW
Big Sandy – Windtalker 230	Story – Burlington Satellite 345	720 MW
Burlington – Bonny Creek – South Fork 115	Story – Burlington Satellite 345	720 MW
N. Yuma – Story 230	Story – Burlington Satellite 345	720 MW

C. Summary

Alternative 7 is able to meet all four of the identified needs. Specifically, Alternative 7:

- Provides new transmission to accommodate at least 400 MW of new generation in eastern Colorado
- Provides new transmission into the Lamar area with the Burlington Satellite – Lamar 345 kV line, thereby significantly improving system reliability.
- Provides connectivity across Tri-State's four state service area with the Boone – ComWal 230 kV line.
- Provides new transmission into the Burlington area with the Story – Burlington Satellite – Lamar 345 kV line, thereby reducing generation curtailment in eastern Colorado under prior outage conditions.

Alternative 7 accommodated increased injection capability of 480 MW at Burlington, 240 MW at Lamar, or 400 MW split evenly between Burlington and

Lamar prior to system constraints. Network upgrades could be constructed to further increase injection capability to higher levels. Most of the transmission lines limiting Burlington injection are all older, conductor limited lines designed for operation below current design standards (100 deg C operation). Structure modifications and/or replacements could occur on any of these lines to allow 100 deg C operation, rather than a full rebuild, to increase injection capability at a reduced cost when compared to a new line or full line rebuild. Alternative 7 demonstrated very similar results to Alternative 3, demonstrating the operating voltage of the Lamar – Burlington transmission line does not materially improve injection capability in eastern Colorado.

Alternative 7 appears to be a reasonable alternative to meeting the identified needs of the study while providing room for additional resource development.

11.9 Alternative 8 Analysis

A. Description

Alternative 8, shown in Figure 10, constructs a new Pawnee – Story – Burlington 345 kV line, a new Burlington – Lamar 230 kV line, a new Burlington – Cheyenne Ridge 345 kV line, and a new Boone – ComWal 230 kV line. It assumes the following transmission components:

1. Pawnee – Story 345 kV
2. Burlington Satellite 345/230 kV Substation (New)
   a. Story – Burlington Satellite 345 kV
   b. Cheyenne Ridge – Burlington Satellite 345 kV
   c. Lamar – Burlington Satellite 230 kV
   d. Landsman Creek – Burlington Satellite 230 kV
   e. Burlington – Burlington Satellite 230 kV
   f. Two (2) 345/230 kV 400MVA transformers
3. ComWal 230 kV Substation (New)
   a. Boone – ComWal 230 kV
   b. Comanche – ComWal 230 kV
   c. Walsenburg – ComWal 230 kV

Alternative 8 would consist of approximately 150 miles of new 345 kV transmission and 130 miles of new 230 kV transmission. The planning level estimate using the MISO exploratory costs totals approximately $641 million.

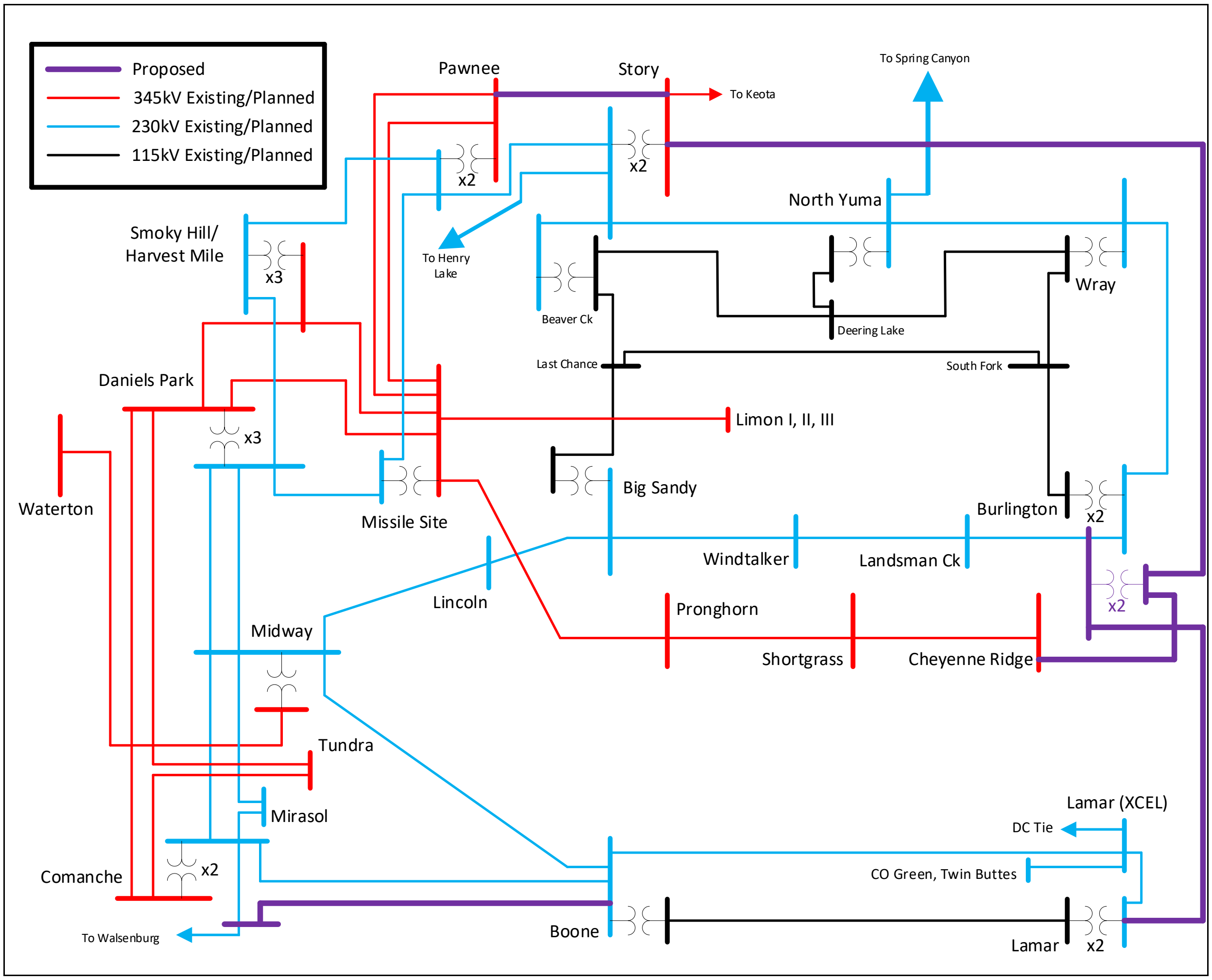

Figure 10: Alternative 8

B. Study Results

Generation was individually injected into the following locations:

1. Story, 400 MW
2. Burlington, 800 MW
3. Lamar, 400 MW
4. Burlington, 400 MW & Lamar, 400 MW

Table 33: Story, 400 MW Injection

Element	Contingency	Generation Accommodated
Smoky Hill – Missile Site 345	Missile Site – Daniels Park 345	80 MW

Table 34: Burlington, 800 MW Injection

Element	Contingency	Generation Accommodated
Big Sandy – Windtalker 230	Missile Site – Pronghorn 345	400 MW
Burlington – Bonny Creek – South Fork 115	Missile Site – Pronghorn 345	560 MW
Missile Site – Smoky Hill 345	Missile Site – Daniels Park 345	640 MW
--- Non Converged ---	Missile Site – Pronghorn 345	>640 MW

Table 35: Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Vilas 115/69 T1	Willow Creek – Lamar 115	160 MW
Lamar – Willow Creek 115	Lamar – Burlington Satellite 230	280 MW
Boone – Lamar 230	Lamar – Burlington Satellite 230	320 MW
--- Non Converged ---	Lamar – Burlington Satellite 230	>360 MW

Table 36: Burlington, 400 MW Injection & Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Vilas 115/69 T1	Willow Creek – Lamar 115	320 MW
Big Sandy – Windtalker 230	Missile Site – Pronghorn 345	480 MW
Lamar – Willow Creek 115	Lamar – Burlington Satellite 230	560 MW
Boone – Lamar 230	Lamar – Burlington Satellite 230	640 MW
Burlington – Bonny Creek – South Fork 115	Missile Site – Pronghorn 345	720 MW
--- Non Converged ---	Lamar – Burlington Satellite 230	>720 MW

C. Summary

Alternative 8 is able to meet all four of the identified needs. Specifically, Alternative 8:

- Provides new transmission to accommodate at least 400 MW of new generation in eastern Colorado
- Provides new transmission into the Lamar area with the Burlington Satellite – Lamar 345 kV line, thereby significantly improving system reliability.
- Provides connectivity across Tri-State's four state service area with the Boone – ComWal 230 kV line.
- Provides new transmission into the Burlington area with the Story – Burlington Satellite – Lamar 345 kV line, thereby reducing generation curtailment in eastern Colorado under prior outage conditions.

Alternative 8 accommodated increased injection capability of 80 MW at Story, 400 MW at Burlington, 160 MW at Lamar, or 320 MW split evenly between Burlington and Lamar prior to system constraints. Network upgrades could be constructed to further increase injection capability to higher levels. Similar to Alternative 5, Alternative 8 demonstrated reduced increases in injection capability in comparison to Alternatives 3, 4, and 7. The reduced benefit can be attributed to networking the Rush Creek Gen-Tie, specifically Cheyenne Ridge, at Burlington. Consistent with observations in the CCPG Rush Creek Task Force and the Lamar Front Range Task Force, networking the Rush Creek Gen-Tie requires the transmission system to accommodate up to 1400 MW of existing generation on the Rush Creek Gen-Tie. For the loss of Missile Site – Pronghorn 345 kV, existing generation on the Rush Creek Gen-Tie is injected into Burlington, thereby utilizing some of the incremental increase in injection capability created by the transmission built out of Burlington.

Alternative 8 appears to be a less reasonable alternative to meeting the identified needs of the study due to the higher cost than Alternatives 3, 4, and 7, at a reduced injection capability.

11.10 Alternative 9 Analysis

A. Description

Alternative 9, shown in Figure 11, constructs a new Pawnee – Story – Cheyenne Ridge – Lamar 345 kV line and a new Boone – ComWal 230 kV line. It assumes the following transmission components:

1. Pawnee – Story 345 kV
2. Story – Cheyenne Ridge 345 kV
3. Lamar 345/230 kV Substation (Substation expansion)
    a. Cheyenne Ridge – Lamar 345 kV
    b. Two (2) 345/230 kV 400MVA transformers
4. ComWal 230 kV Substation (New)
    a. Boone – ComWal 230 kV
    b. Comanche – ComWal 230 kV
    c. Walsenburg – ComWal 230 kV

Alternative 9 would consist of approximately 225 miles of new 345 kV transmission and 35 miles of new 230 kV transmission. The planning level estimate using the MISO exploratory costs totals approximately $689.5 million.

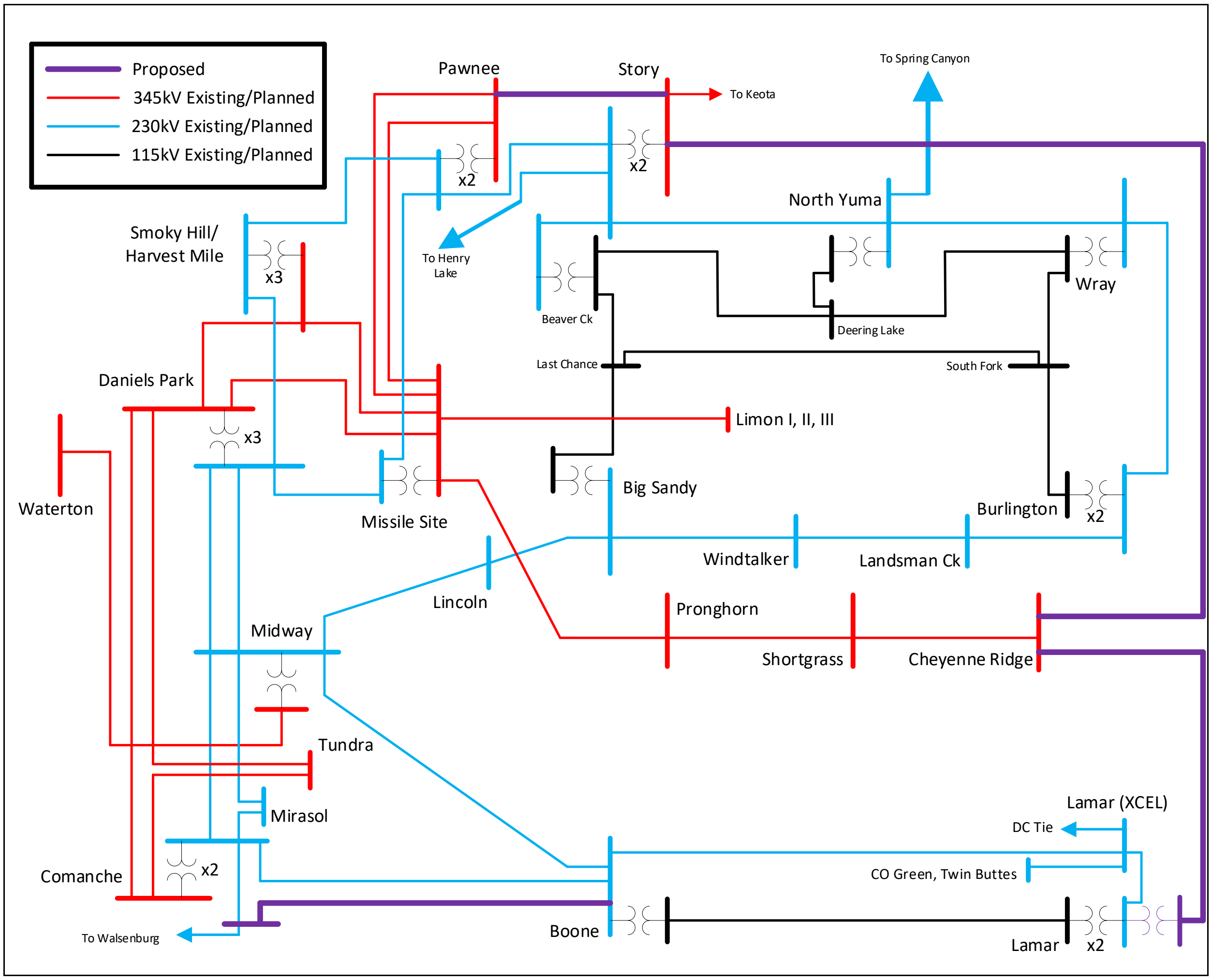

Figure 11: Alternative 9

B. Study Results

Generation was individually injected into the following locations:

1. Story, 400 MW
2. Cheyenne Ridge, 400 MW
3. Lamar, 400 MW
4. Burlington, 400 MW & Lamar, 400 MW

Table 37: Story, 400 MW Injection

Element	Contingency	Generation Accommodated
Vilas 115/69 T1	Lamar – Willow Creek 115	80 MW
Smoky Hill – Missile Site 345	Missile Site – Daniels Park 345	160 MW

Table 38: Cheyenne Ridge, 400 MW Injection

Element	Contingency	Generation Accommodated
Lamar – Willow Creek 115	Missile Site – Pronghorn 345	80 MW
--- Non Converged ---	Missile Site – Pronghorn 345	>160 MW

Table 39: Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Lamar – Willow Creek 115	Missile Site – Pronghorn 345	80 MW
--- Non Converged ---	Missile Site – Pronghorn 345	>240 MW

Table 40: Cheyenne Ridge, 400 MW Injection & Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Lamar – Willow Creek 115	Missile Site – Pronghorn 345	80 MW
--- Non Converged ---	Missile Site – Pronghorn 345	>240 MW

C. Summary

Alternative 9 is able to meet two of the four identified needs. Specifically, Alternative 9:

- Provides new transmission into the Lamar area with the Cheyenne Ridge – Lamar 230 kV line, thereby significantly improving system reliability.
- Provides connectivity across Tri-State's four state service area with the Boone – ComWal 230 kV line.

Alternative 9 accommodated increased injection capability of 80 MW at Story, 80 MW at Cheyenne Ridge, 80 MW at Lamar, or 80 MW split evenly between Cheyenne Ridge and Lamar prior to system constraints. Network upgrades could be constructed to further increase injection capability to higher levels. The reduced benefit can be attributed to networking the Rush Creek Gen-Tie, specifically Cheyenne Ridge, at Lamar. Consistent with observations in the CCPG Rush Creek Task Force and the Lamar Front Range Task Force, networking the Rush Creek Gen-Tie requires the transmission system to accommodate up to 1400 MW of existing generation on the Rush Creek Gen-Tie. For the loss of Missile Site – Pronghorn 345 kV, existing generation on the Rush Creek Gen-Tie is injected into Lamar, thereby further stressing a constrained system. Additionally, voltage support would be required to support the heavy transfers from Cheyenne Ridge to Story and Lamar.

Alternative 9 did not have any connections to the eastern Colorado 230 kV transmission system. The lack of connections fails to mitigate generation curtailment in eastern Colorado under prior outage conditions.

Alternative 9 does not appear to be a reasonable alternative to meeting the identified needs of the study.

11.11 Alternative 10 Analysis

A. Description

Alternative 10, shown in Figure 12, constructs a new Pawnee – Story – Cheyenne Ridge – Lamar – Tundra 345 kV line and a new Boone – ComWal 230 kV line. It assumes the following transmission components:

1. Pawnee – Story 345 kV
2. Story – Cheyenne Ridge 345 kV
3. Lamar 345/230 kV Substation (Substation expansion)
    a. Cheyenne Ridge – Lamar 345 kV
    b. Tundra – Lamar 345 kV
    c. Two (2) 345/230 kV 400MVA transformers
4. ComWal 230 kV Substation (New)
    a. Boone – ComWal 230 kV
    b. Comanche – ComWal 230 kV
    c. Walsenburg – ComWal 230 kV

Alternative 10 would consist of approximately 350 miles of new 345 kV transmission and 35 miles of new 230 kV transmission. The planning level estimate using the MISO exploratory costs totals approximately $1.039 billion.

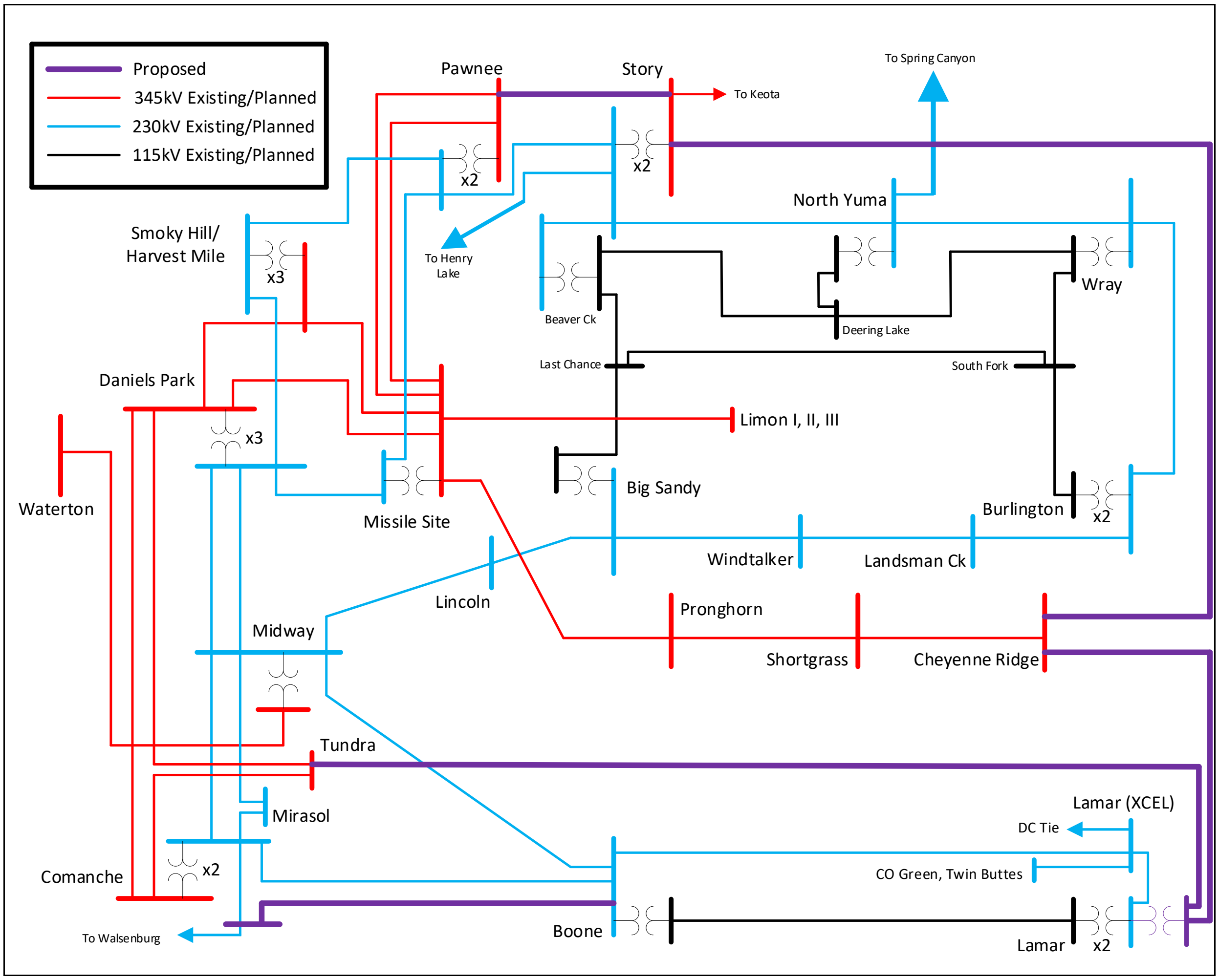

Figure 12: Alternative 10

B. Study Results

Generation was individually injected into the following locations:

1. Story, 800 MW
2. Cheyenne Ridge, 800 MW
3. Lamar, 1500 MW
4. Cheyenne Ridge, 800 MW & Lamar, 800 MW

Table 41: Story, 800 MW Injection

Element	Contingency	Generation Accommodated
Smoky Hill – Missile Site 345	Missile Site – Daniels Park 345	560 MW

Table 42: Cheyenne Ridge, 800 MW Injection

Element	Contingency	Generation Accommodated
--- Non Converged ---	Missile Site – Pronghorn 345	720 MW

Table 43: Lamar, 1500 MW Injection

Element	Contingency	Generation Accommodated
Lamar – Willow Creek 115	Lamar – Tundra 345	960 MW

Table 44: Cheyenne Ridge, 800 MW Injection & Lamar, 800 MW Injection

Element	Contingency	Generation Accommodated
--- Non Converged ---	Missile Site – Pronghorn 345	960 MW

C. Summary

Alternative 10 is able to meet three of the identified needs. Specifically, Alternative 10:

- Provides new transmission to accommodate at least 400 MW of new generation in eastern Colorado
- Provides new transmission into the Lamar area with the Cheyenne Ridge – Lamar 345 kV line, thereby significantly improving system reliability.
- Provides connectivity across Tri-State's four state service area with the Boone – ComWal 230 kV line.

Alternative 10 accommodated increased injection capability of 560 MW at Story, 720 MW at Burlington, 960 MW at Lamar, or 960 MW split evenly between Burlington and Lamar prior to system constraints. Network upgrades could be constructed to further increase injection capability to higher levels. Alternative 10 demonstrated greater increases in injection capability in comparison to most previous alternatives. The increase benefit can be attributed to additional 345 kV connection between Lamar and Tundra, creating a third[14] 345 kV path from eastern Colorado towards the Front Range. Similar to Alternative 9, for the loss of Missile Site – Pronghorn 345 kV, existing generation on the Rush Creek Gen-Tie is injected into Lamar, which is already

[14] The other two paths are the Cheyenne Ridge – Story 345 kV, considered in Alternative 9, and the existing Missile Site – Pronghorn – Shortgrass – Cheyenne Ridge 345 kV line (known as the Rush Creek Gen-Tie).

constrained. Additionally, voltage support would be required to support the heavy transfers from Cheyenne Ridge to Story, Lamar, and Tundra.

Alternative 10 did not have any connections to the eastern Colorado 230 kV transmission system. The lack of connections fails to mitigate generation curtailment in eastern Colorado under prior outage conditions.

Alternative 10 does not appear to be a reasonable alternative to meeting the identified needs of the study.

11.12 Alternative 11 Analysis

A. Description

Alternative 11, shown in Figure 13, constructs a new StoHen – Big Sandy 230 kV line, a new Big Sandy – Boone 230 kV line, a new Boone – ComWal 230 kV, and rebuilds the Big Sandy – Burlington 230 kV line. It assumes the following transmission components:

1. Rebuild Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV
2. StoHen 230 kV Substation
    a. Story – StoHen 230 kV
    b. Henry Lake – StoHen 230 kV
    c. Big Sandy – StoHen 230 kV
3. Big Sandy – Boone 230 kV
4. ComWal 230 kV Substation
    a. Boone – ComWal 230 kV
    b. Comanche – ComWal 230 kV
    c. Walsenburg – ComWal 230 kV

Alternative 11 would consist of approximately 191 miles of new 230 kV transmission and 81 miles of rebuilt/uprated 230 kV transmission. The planning level estimate using the MISO exploratory costs totals approximately $462.4 million.

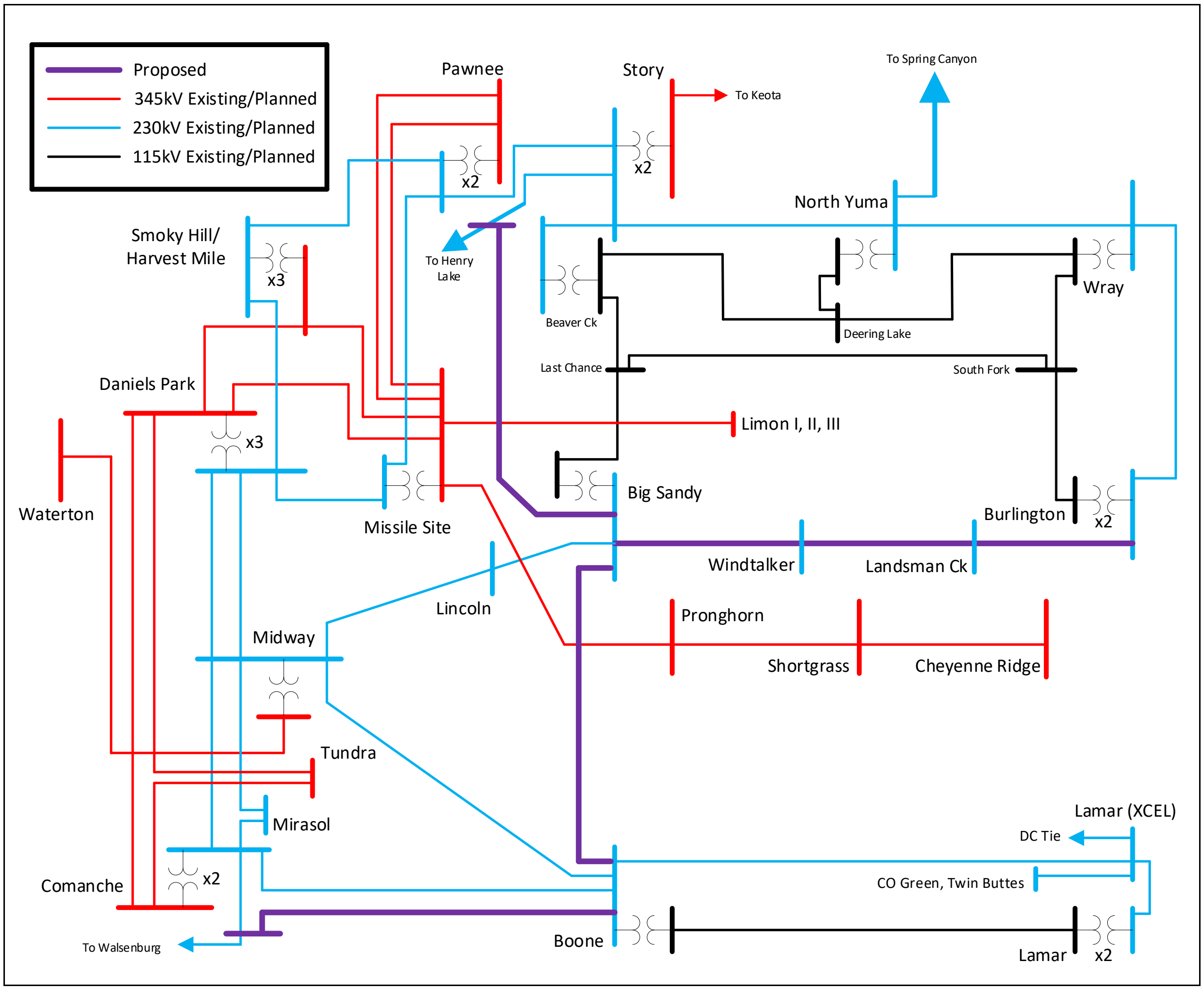

Figure 13: Alternative 11

B. Study Results

Generation was individually injected into the following locations:

1. Story, 400 MW
2. Burlington, 400 MW
3. Big Sandy, 800 MW
4. Lamar, 400 MW

Table 45: Story, 400 MW Injection

Element	Contingency	Generation Accommodated
Smoky Hill – Missile Site 345	Missile Site – Daniels Park 345	0 MW

Table 46: Burlington, 400 MW Injection

Element	Contingency	Generation Accommodated
South Fork – Joes – Last Chance 115	Big Sandy – Windtalker 230	25 MW
Incremental 115 kV Violations	Multiple 230 Outages	25-400 MW
Incremental 230 kV Violations	Multiple 230 Outages	25-400 MW

Table 47: Big Sandy, 800 MW Injection

Element	Contingency	Generation Accommodated
Burlington – Bonny Creek – South Fork 115	Burlington – Wray 230	640 MW
Deering Lake – E. Yuma – Eckley 115	North Yuma – Wray 230	640 MW

Table 48: Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Willow Ck – Lamar 115	Lamar – Boone 230	25 MW

C. Summary

Alternative 11 is able to meet three of the four identified needs. Specifically, Alternative 11:

- Provides new transmission to accommodate at least 400 MW of new generation in eastern Colorado
- Provides connectivity across Tri-State's four state service area with the Boone – ComWal 230 kV line.
- Provides new transmission into the Limon area with the Story – Big Sandy – Boone 230 kV line, thereby reducing generation curtailment in eastern Colorado under prior outage conditions.

Alternative 11 accommodated increased injection capability of 25 MW at Burlington, 640 MW at Big Sandy, and 25 MW at Lamar. Network upgrades could be constructed to further increase injection capability to higher levels. Little to no increased injection capability was observed at Burlington and Lamar due to lack on additional transmission out of these substations, providing focused improvement in system injection capability. No limitations were observed on the Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV line, indicating a full rebuild may not be required. Additionally, the lack of additional transmission into Lamar failed to mitigate the existing reliability concerns in the Lamar area.

Alternative 11 does not appear to be a reasonable alternative to meeting the identified needs of the study.

11.13 Alternative 12 Analysis

A. Description

Alternative 12, shown in Figure 14, constructs a new Story– Big Sandy 230 kV line, a new Big Sandy – Boone 230 kV line, a new Boone – ComWal 230 kV, and rebuilds the Big Sandy – Burlington 230 kV line. It assumes the following transmission components:

1. Rebuild Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV
2. Big Sandy – Story 230 kV
3. Big Sandy – Boone 230 kV
4. ComWal 230 kV Substation (New)
    a. Boone – ComWal 230 kV
    b. Comanche – ComWal 230 kV
    c. Walsenburg – ComWal 230 kV

Alternative 12 would consist of approximately 198 miles of new 230 kV transmission and 81 miles of rebuilt/uprated 230 kV transmission. The planning level estimate using the MISO exploratory costs totals approximately $474.3 million.

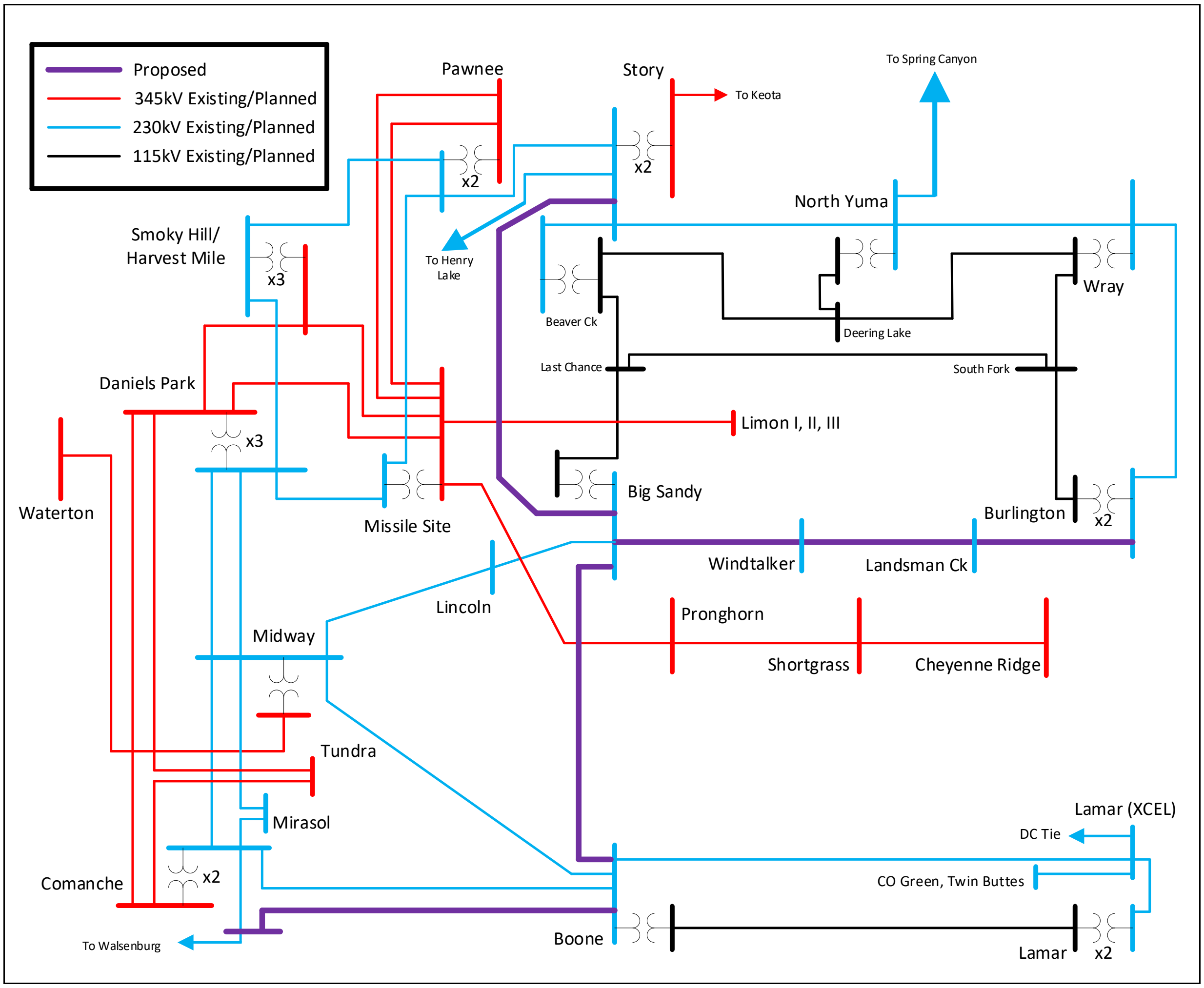

Figure 14: Alternative 12

B. Study Results

Generation was individually injected into the following locations:

1. Story, 400 MW
2. Burlington, 400 MW
3. Big Sandy, 800 MW
4. Lamar, 400 MW

Table 49: Story, 400 MW Injection

Element	Contingency	Generation Accommodated
Smoky Hill – Missile Site 345	Missile Site – Daniels Park 345	0 MW

Table 50: Burlington, 400 MW Injection

Element	Contingency	Generation Accommodated
South Fork – Joes – Last Chance 115	Big Sandy – Windtalker 230	25 MW
Incremental 115 kV Violations	Multiple 230 Outages	25-400 MW
Incremental 230 kV Violations	Multiple 230 Outages	25-400 MW

Table 51: Big Sandy, 800 MW Injection

Element	Contingency	Generation Accommodated
Burlington – Bonny Creek – South Fork 115	Burlington – Wray 230	640 MW
Deering Lake – E. Yuma – Eckley 115	North Yuma – Wray 230	640 MW

Table 52: Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Willow Ck – Lamar 115	Lamar – Boone 230	25 MW

C. Summary

Alternative 12 is able to meet three of the four identified needs. Specifically, Alternative 12:

- Provides new transmission to accommodate at least 400 MW of new generation in eastern Colorado
- Provides connectivity across Tri-State's four state service area with the Boone – ComWal 230 kV line.
- Provides new transmission into the Limon area with the Story – Big Sandy – Boone 230 kV line, thereby reducing generation curtailment in eastern Colorado under prior outage conditions.

Alternative 12 accommodated increased injection capability of 25 MW at Burlington, 640 MW at Big Sandy, and 25 MW at Lamar. Network upgrades could be constructed to further increase injection capability to higher levels. Little to no increased injection capability was observed at Burlington and Lamar due to lack on additional transmission out of these substations, providing focused improvement in system injection capability. No limitations were observed on the Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV line, indicating a full rebuild may not be required. Additionally, the lack of additional transmission into Lamar failed to mitigate the existing reliability concerns in the Lamar area. Results were nearly identical to Alternative 11, indicating that connections into Story versus the Story – Henry Lake 230 kV provide comparable results.

Alternative 12 does not appear to be a reasonable alternative to meeting the identified needs of the study.

11.14 Alternative 13 Analysis

A. Description

Alternative 13, shown in Figure 15, constructs a new Story – Big Sandy 230 kV line, a new Boone – ComWal 230 kV line, and rebuilds the Big Sandy – Burlington 230 kV. It assumes the following transmission components:

1. Rebuild Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV
2. Story – Big Sandy 230 kV
3. ComWal 230 kV Substation
    a. Boone – ComWal 230 kV
    b. Comanche – ComWal 230 kV
    c. Walsenburg – ComWal 230 kV

Alternative 13 would consist of approximately 112 miles of new 230 kV transmission and 81 miles of rebuilt/uprated 230 kV transmission. The planning level estimate using the MISO exploratory costs totals approximately $328.1 million.

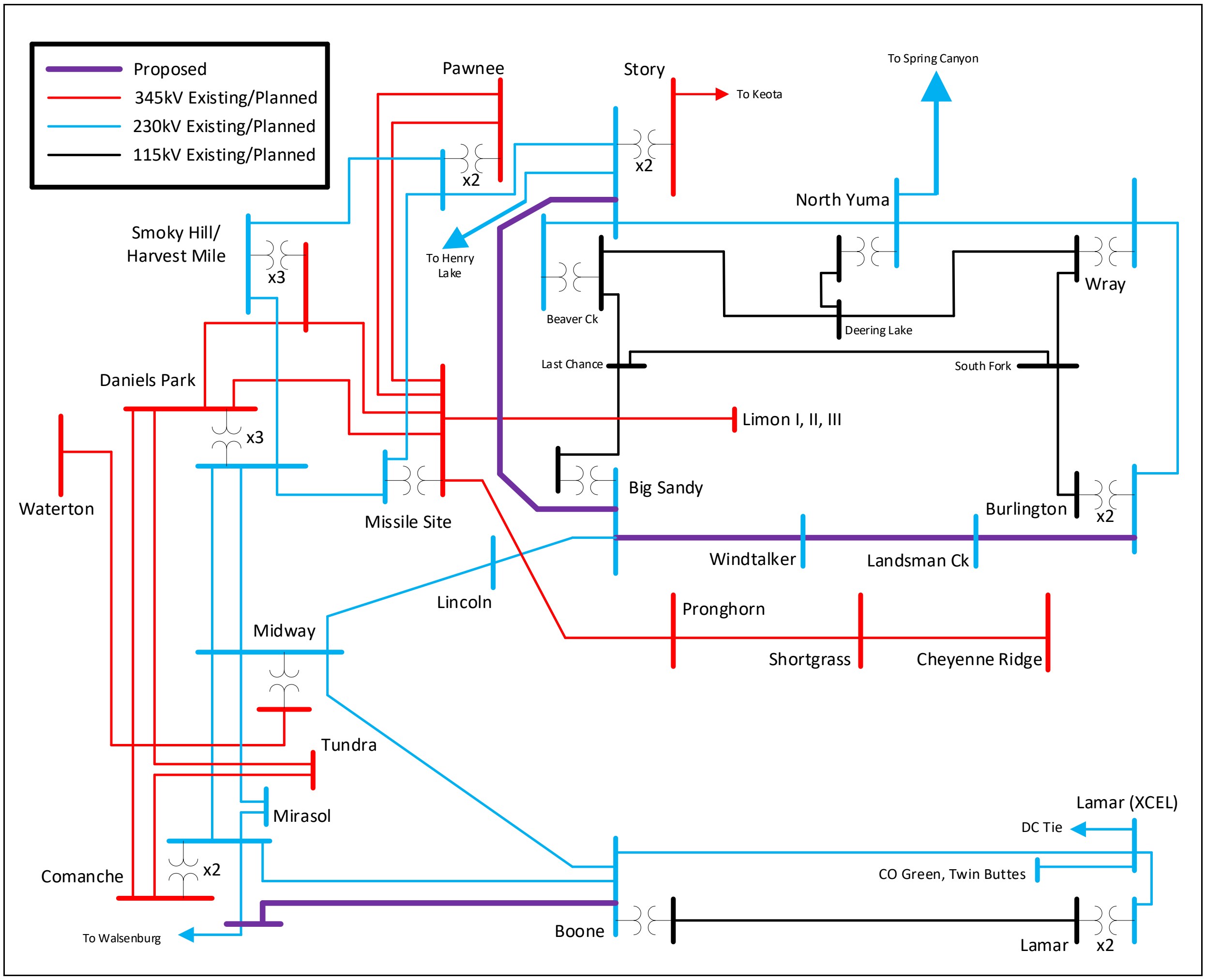

Figure 15: Alternative 13

B. Study Results

Generation was individually injected into the following locations:

1. Story, 400 MW
2. Burlington, 400 MW
3. Big Sandy, 800 MW
4. Lamar, 400 MW

Table 53: Story, 400 MW Injection

Element	Contingency	Generation Accommodated
Smoky Hill – Missile Site 345	Missile Site – Daniels Park 345	0 MW

Table 54: Burlington, 400 MW Injection

Element	Contingency	Generation Accommodated
South Fork – Joes – Last Chance 115	Big Sandy – Windtalker 230	25 MW
Incremental 115 kV Violations	Multiple 230 Outages	25-400 MW
Incremental 230 kV Violations	Multiple 230 Outages	25-400 MW

Table 55: Big Sandy, 800 MW Injection

Element	Contingency	Generation Accommodated
Deering Lake – E. Yuma – Eckley 115	North Yuma – Wray 230	400 MW
Incremental 115 kV Violations	Multiple 230 Outages	400-800 MW
Incremental 230 kV Violations	Multiple 230 Outages	400-800 MW

Table 56: Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Willow Ck – Lamar 115	Lamar – Boone 230	25 MW

C. Summary

Alternative 13 is able to meet three of the four identified needs. Specifically, Alternative 13:

- Provides new transmission to accommodate at least 400 MW of new generation in eastern Colorado
- Provides connectivity across Tri-State's four state service area with the Boone – ComWal 230 kV line.
- Provides new transmission into the Limon area with the Story – Big Sandy 230 kV line, thereby reducing generation curtailment in eastern Colorado under prior outage conditions.

Alternative 13 accommodated increased injection capability of 25 MW at Burlington, 400 MW at Big Sandy, and 25 MW at Lamar. Network upgrades could be constructed to further increase injection capability to higher levels. Little to no increased injection capability was observed at Burlington and Lamar due to lack on additional transmission out of these substations, providing focused improvement in system injection capability. No limitations were observed on the Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV line, indicating a full rebuild may not be required. Additionally, the lack of additional transmission into Lamar failed to mitigate the existing reliability concerns in the Lamar area. Injection capability was reduced at Big Sandy in comparison to Alternatives 11 and 12. This can be attributed to Big Sandy – Boone 230 kV, which provides an additional exit out of the Big Sandy area.

Alternative 13 does not appear to be a reasonable alternative to meeting the identified needs of the study.

11.15 Alternative 14 Analysis

A. Description

Alternative 14, shown in Figure 16, constructs a new Big Sandy – Story 230 kV line, a new Burlington – Lamar 230 kV line, a new Boone – ComWal 230 kV line, and rebuilds the Big Sandy – Burlington 230 kV. It assumes the following transmission components:

1. Rebuild Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV
2. Story – Big Sandy 230 kV
3. Burlington – Lamar 230 kV
4. ComWal 230 kV Substation
   a. Boone – ComWal 230 kV
   b. Comanche – ComWal 230 kV
   c. Walsenburg – ComWal 230 kV

Alternative 14 would consist of approximately 207 miles of new 230 kV transmission and 81 miles of rebuilt/uprated 230 kV transmission. The planning level estimate using the MISO exploratory costs totals approximately $489.6 million.

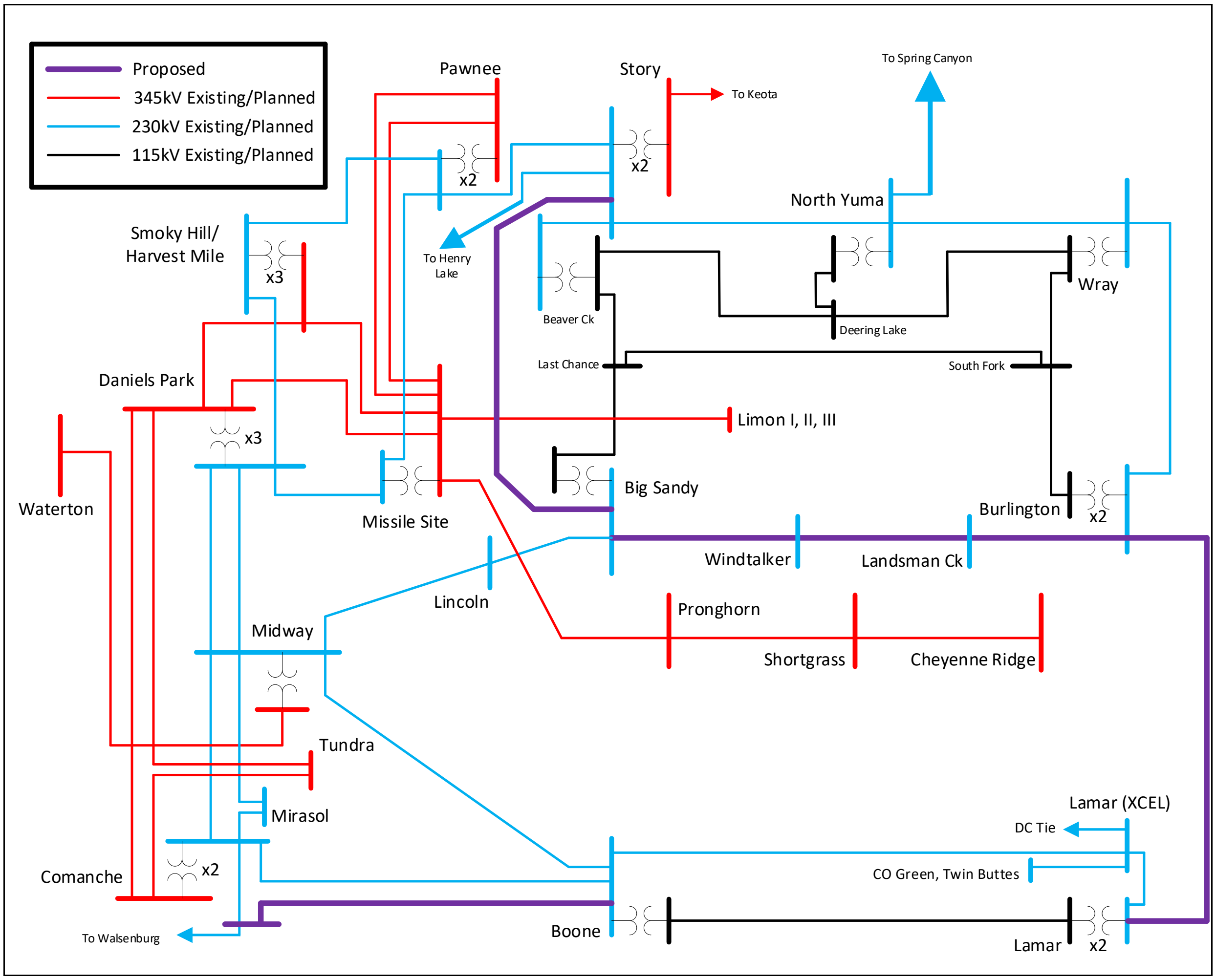

Figure 16: Alternative 14

B. Study Results

Generation was individually injected into the following locations:

1. Story, 400 MW
2. Burlington, 400 MW
3. Lamar, 400 MW
4. Big Sandy, 800 MW
5. Big Sandy, 400 MW & Lamar, 400 MW

Table 57: Story, 400 MW Injection

Element	Contingency	Generation Accommodated

Smoky Hill – Missile Site 345	Missile Site – Daniels Park 345	0 MW

Table 58: Burlington, 400 MW Injection

Element	Contingency	Generation Accommodated
South Fork – Joes – Last Chance 115	Big Sandy – Windtalker 230	160 MW
Deering Lake – E. Yuma – Eckley 115	Wray – N. Yuma 230	200 MW
Burlington – Bonny Creek – South Fork 115	Burlington – Wray 230	200 MW
N. Yuma – Story 230	Big Sandy – Windtalker 230	240 MW
Deering Lake – Akron – Beaver Creek 115	N. Yuma – Story 230	280 MW

Table 59: Lamar, 400 MW Injection

Element	Contingency	Generation Accommodated
Vilas 115/69 T1	Lamar – Willow Creek 115	160 MW
South Fork – Joes – Last Chance 115	Big Sandy – Windtalker 230	280 MW
Lamar – Willow Creek 115	Burlington – Lamar 230	280 MW
Boone – Lamar 230	Burlington – Lamar 230	320 MW
Deering Lake – E. Yuma – Eckley 115	Wray – N. Yuma 230	360 MW
Burlington – Bonny Creek – South Fork 115	Burlington – Wray 230	360 MW

Table 60: Big Sandy, 800 MW Injection

Element	Contingency	Generation Accommodated
Big Sandy – Last Chance 115	Big Sandy – Story 230	480 MW

Table 61: Lamar, 400 MW Injection & Big Sandy, 400 MW

Element	Contingency	Generation Accommodated
Vilas 115/69 T1	Lamar – Willow Creek 115	240 MW
Deering Lake – E. Yuma – Eckley 115	Wray – N. Yuma 230	480 MW
Burlington – Bonny Creek – South Fork 115	Burlington – Wray 230	560 MW
Lamar – Willow Creek 115	Burlington – Lamar 230	560 MW
Boone – Lamar 230	Burlington – Lamar 230	640 MW
Big Sandy – L. Chance – Woodrow – Beaver Ck 115	Big Sandy – Story 230	720 MW
Deering Lake – Akron – Beaver Creek 115	N. Yuma – Story 230	720 MW

C. Summary

Alternative 14 is able to meet all four of the identified needs. Specifically, Alternative 14:

- Provides new transmission to accommodate at least 400 MW of new generation in eastern Colorado
- Provides new transmission into the Lamar area with the Burlington – Lamar 230 kV line, thereby significantly improving system reliability.

- Provides connectivity across Tri-State's four state service area with the Boone – ComWal 230 kV line.
- Provides new transmission into the Big Sandy and Burlington areas with the Story – Big Sandy 230 kV and the Burlington – Lamar 230 kV line, respectively, thereby reducing generation curtailment in eastern Colorado under prior outage conditions.

Alternative 14 accommodated increased injection capability of 160 MW at Burlington, 160 MW at Lamar, 480 MW at Big Sandy, or 240 MW split evenly between Big Sandy and Lamar prior to system constraints. Network upgrades could be constructed to further increase injection capability to higher levels. While Alternative 14 provides 560 MW of injection capability, the constraining element is the existing Big Sandy – Last Chance 115 kV line is limiting which would necessitate additional transmission out of Big Sandy or elsewhere in eastern Colorado to increase injection capability. No limitations were observed on the Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV line, indicating a full rebuild may not be required.

Alternative 14 appears to be a reasonable alternative to meeting the identified needs of the study while providing slightly less room for additional resource development when compared to Alternatives 3, 4, and 7.

11.16 Power Flow Results Summary

Alternatives were evaluated on their ability to meet the identified objectives and needs stated in Section 3.0, which include an alternative's ability to:

1. Accommodate at least 400 MW of new generation in eastern Colorado
2. Provide connectivity between Tri-State's four state service area, which currently is not connected in southeast Colorado.
3. Improve Lamar transmission system reliability, specifically related to the Lamar-Boone 230 kV line outage.
4. Mitigate generation curtailment in eastern Colorado under prior outage conditions.

A summary of the REPTF Alternatives is shown below.

Table 62: Alternatives Summary (Transmission Elements)

Proposed Transmission Element	Mileage	Alternative														
		1	2	3	4	5	6	6B	7	8	9	10	11	12	13	14
Pawnee - Story 345 kV	10				x	x	x	x		x	x	x				
Story - Burlington 230 kV	120		x													
Story - Burlington 345 kV	120			x	x	x	x	x	x	x						
Story-Cheyenne Ridge 345 kV	140										x	x				
Burlington - Cheyenne Ridge 345 kV	20					x	x	x		x						
Burlington - Lamar 230 kV	95		x						x	x						x
Burlington - Lamar 345 kV	95			x	x	x	x	x								
Cheyenne Ridge - Lamar 345 kV	75										x	x				
Lamar - Tundra 345 kV	125						x					x				
Lamar - Boone 230 kV	99							x								
Boone - ComWal 230 kV	35		x	x	x	x	x	x	x	x	x	x	x	x	x	x
Big Sandy - StoHen 230 kV	70												x			
Big Sandy - Story 230 kV	77													x	x	x
Big Sandy - Boone 230 kV	86												x	x		
Big Sandy - ... - Burlington 230 kV Uprate/Rebuild	81												x	x	x	x

A summary of REPTF Alternatives associated line miles is shown below.

Table 63: Alternatives Summary (Line Mileage)

Alternative	Estimated Line Miles			
	New 230kV	New 345kV	Rebuild 230kV	TOTAL
1	0	0	0	0
2	250	0	0	250
3	35	215	0	250
4	35	225	0	260
5	35	245	0	280
6	35	370	0	405
6B	135	245	0	380
7	130	120	0	250
8	130	150	0	280
9	35	225	0	260
10	35	350	0	385
11	191	0	81	272
12	198	0	81	279
13	112	0	81	193
14	207	0	81	288

A summary of the power flow results, including costs and ability to meet identified objectives and needs, is shown below. Alternatives that were able to meet all the identified objectives and needs are highlighted green.

Table 64: Alternatives Summary (Results)

Alternative	Cost ($M)	Generation Injection Limit		Total Needs Met
		Highest Standalone Injection	Combined Injection	
1	Varies	0-50	n/a	2
2	$425.0	360	280	3
3	$661.5	560	560	4
4	$689.5	560	560	4
5	$745.5	400	480	4
6	$1,095.5	1050	1280	4
6B	$915.5	720	800	4
7	$557.0	480	320	4
8	$641.0	400	320	4
9	$689.5	80	80	2
10	$1,039.5	960	960	3
11	$462.4	640	n/a	3
12	$474.3	640	n/a	3
13	$328.1	400	n/a	3
14	$489.6	480	240	4

While each alternative demonstrated an ability to meet at least two of the identified objectives and needs, only eight (8) of the fifteen (15) alternatives were able to meet all the objectives and needs. The eight alternatives that met the objectives and needs can generally be grouped into two categories: base alternatives, and expanded alternatives.

Base alternatives could be described as initial buildout options. Alternatives 3, 7, and 14 are base alternatives and include the base transmission needed to meet the identified objectives and needs. As discussed in Section 11.8, Alternative 7 demonstrated very similar performance to Alternative 3. The comparable performance of Alternatives 3 and 7 demonstrates the operating voltage of the Lamar – Burlington transmission line does not materially improve injection capability or reliability in eastern Colorado. Contrary to Alternatives 3 and 7, which proposed all new transmission, Alternative 14 proposed the full rebuild of the existing Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV line in addition to new transmission. Notably, the lack of limitations observed on the Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV line indicate a full rebuild may not be required. Further detailed engineering analysis would be required to determine if limited[15] structure modifications and/or replacements could be performed to achieve an acceptable higher rating thereby avoiding the full rebuild.

Expanded alternatives could be described as long-term buildout alternatives, or alternatives for joint participation to meet multiple Colorado utility's resource needs. Alternatives 4, 5, 6, 6B, and 8 are expanded alternatives and include additional transmission elements on top of a "base alternative." Specifically, Alternatives 4, 5, 6, and 6B build upon each other, and all build upon Alternative 3. As discussed in Section 11.4, Alternative 4 demonstrated near identical results to Alternative 3, demonstrating the addition of the Pawnee – Story 345 kV does not assist in meeting any of the identified needs or materially improve injection capability in eastern Colorado. Similarly, Alternative 8 builds upon Alternative 7, adding connections into Pawnee and Cheyenne Ridge.

An important ranking criterion used was the ability for each alternative to meet the identified objectives and needs at the lowest cost. Alternatives 7 and 14 were found to able to meet the identified objectives and needs at the lowest cost. Notably with Alternative 14, if the Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV line were found to not require a full rebuild, the estimated cost would be significantly reduced[16]. Alternatives 6 and 6B were found to be the most expensive alternatives which is reflective of the significant transmission buildout associated with these alternatives. Specifically, Alternatives 6 and 6B each include multiple new

[15] The Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV is an older line designed for only 50 deg C operation, rather than standard 100 deg C. For some lines limited structure modifications and/or replacements can increase a line's operating temperature to 75 or 100 deg C, resulting in an increased thermal rating.

[16] The full rebuild of Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV line accounts for $137.7M of Alternative 14's estimated cost.

transmission paths towards the Front Range. A cost ranking of alternatives that met all the objectives and needs is shown below. Base alternatives are listed in **bold**.

Table 65: Cost Ranking

Alternative	Estimated Cost ($M)
14	**489.6**
7	**557.0**
8	641.0
3	**661.5**
4	689.5
5	745.5
6B	915.5
6	1095.5

An alternative ranking criterion utilized by the REPTF was a measure of injection capability gained per unit cost ($M) which measured the resource accommodation of each dollar spent. This ranking criterion was calculated by dividing the highest standalone injection by the estimated cost for each respective alternative that met all the identified objectives and needs. This could be described as a "bang for your buck" measurement criterion. Alternatives 6 and 14 were found to provide the highest resource accommodation per unit cost. Alternatives 5 and 8 provided the lowest resource accommodation per unit cost. The lowest ranked alternatives all include networking into the Rush Creek Gen-Tie at Cheyenne Ridge with limited new transmission paths back towards the Front Range. A ranking of alternatives based on injection capability per dollar ($M) cost is shown below. Base alternatives are listed in **bold**.

Table 66: MW/$M Cost Ranking

Alternative	Estimated Cost ($M)	Standalone Injection Limit (MW)	MW/$M Ratio
14	**489.6**	**480**	**0.980**
6	1095.5	1050	0.958
7	**557**	**480**	**0.862**
3	**661.5**	**560**	**0.847**
4	689.5	560	0.812
6B	915.5	720	0.786
8	641	400	0.624
5	745.5	400	0.537

Cost aside, some stakeholders saw value in the 345 kV construction of alternatives to prevent the need to upgrade 230 kV lines in the future, provide a 345 kV backbone in eastern Colorado, and/or to reduce the cost of future interconnections by avoiding voltage transformation between 230 kV and 345 kV systems. The same stakeholders believe having a robust 345 kV backbone with multiple utility interconnections and pathways to the Front Range is in Colorado utilities' long-term interest under climate statute and market conditions. Of the alternatives that were evaluated and met the objectives and needs, only Alternative 14 did so without 345 kV construction and the associated voltage transformation.

Some consideration was given to the ability for each alternative to accommodate future growth locally and regionally. While none of the alternatives are regional in nature, each of the alternatives connected into, or near, Story substation, which is a major transmission hub in northeast Colorado with direct connection north to Laramie River Station in Wyoming. The additional connection into or near Story further strengthens this existing transmission hub making it a robust hub or connection point for future regional transmission development.

All of the alternatives accommodated future eastern Colorado load growth locally and improved system performance and reliability. Of the alternatives that were evaluated and met the objectives and needs, only Alternatives 5 and 8 did not initially accommodate more than 400 MW of new generation in eastern Colorado. Additional transmission network upgrades would be required in these two alternatives to accommodate more than 400 MW of new generation. The remaining alternatives provided for additional generation development, while Alternatives 6 and 6B accommodated the largest amount of new generation in eastern Colorado.

Based upon the above criteria, the most cost-effective alternatives to meet the objectives and needs were Alternatives 7 and 14. Alternative 14 could further separate itself as a cost-effective alternative if the Burlington – Landsman Creek – Windtalker – Big Sandy 230 kV line segments are determined to not require a full rebuild. The most cost-effective alternative to meet the needs of multiple Colorado utilities was Alternative 6, albeit at a cost of over $1 billion. Using the evaluation criteria, Alternatives 3, 4, 5, 6B, and 8 did not distinguish themselves as being more cost-effective solutions. Some stakeholders believe the long-term reliability and system benefits provided by increased transmission connections and 345 kV construction make the expanded alternatives (4, 5, 6, 6B, and 8) worthy of consideration today.

12.0 SENSITIVITY RESULTS

The REPTF elected to perform sensitivity power flow analysis to determine the potential impact of select alternatives on PSCo's proposed CPP Project. The alternatives selected for sensitivity analysis were determined based on ability to meet the four identified objectives and needs. Each selected alternative had the proposed CPP Project added to the study model and generation re-dispatched as to increase the aggregate CPP Project and Missile Site generation to approximately 3100 MW, a value consistent with the studies performed in CCPG's 80x30 Task Force which evaluated the project. The aggregate 3100 MW of generation reflects the geographically diverse dispatch utilized in the 80x30 Task Force studies and does not severely stress the proposed CPP project. As a result, no reactive support or grid reinforcement technologies were added to the transmission system as part of the proposed CPP project. Sensitivity analysis was not performed at Alternative 6 due to significant similarities with the proposed CPP Project.

Additional sensitivity analysis was performed on Alternatives 3, 4, 7, and 14 utilizing ATT (power flow control) technology to determine if ATT could enhance generation accommodated in eastern Colorado. Results for each alternative are listed below. Results in parentheses '( )' indicated the pre-CPP injection level or pre-ATT injection level.

12.1 Alternative 3 Sensitivity Analysis

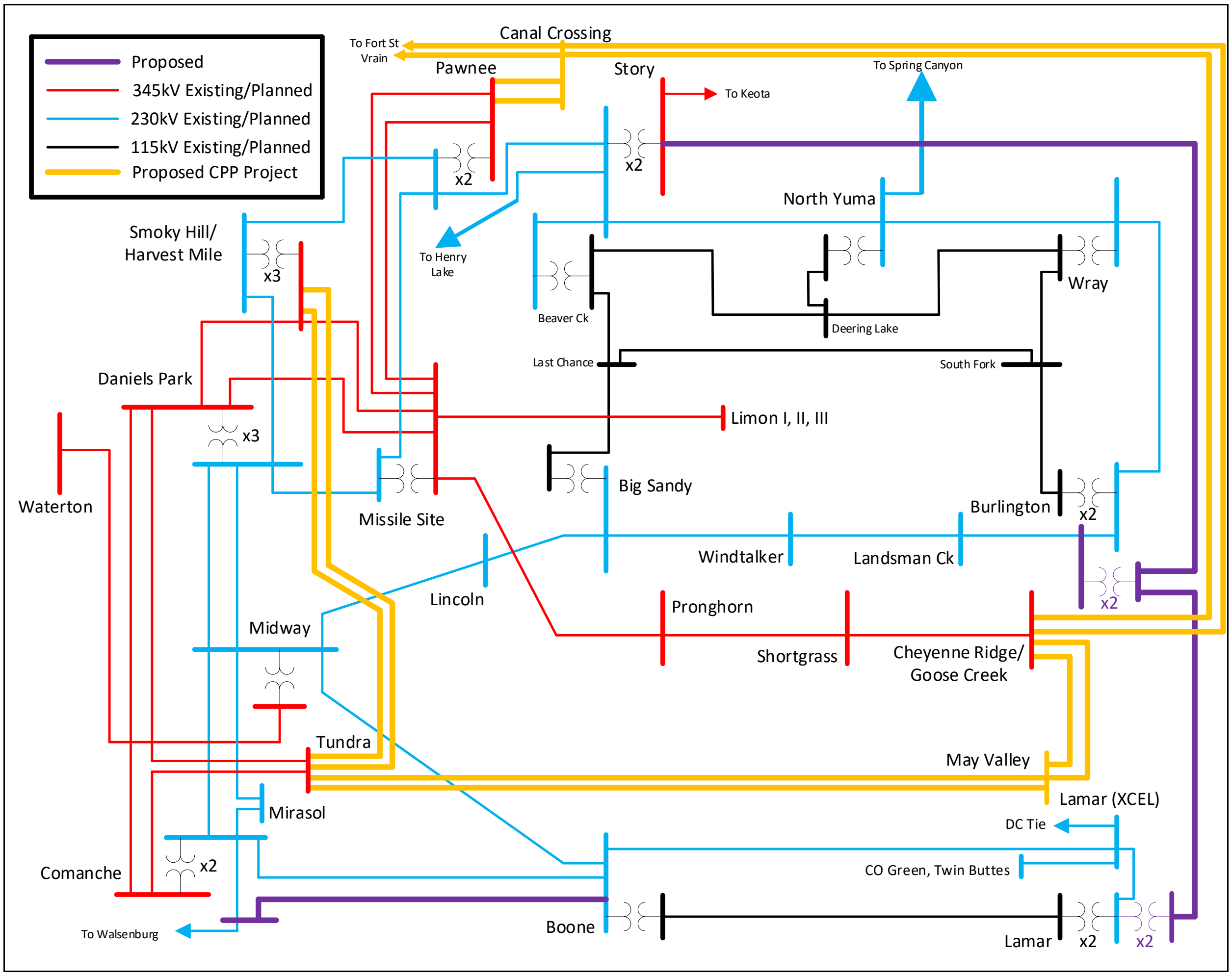

Figure 17: Alternative 3 w/ proposed CPP Project

A. Study Results

Generation was individually injected into the following locations:

1. Story, 800 MW
2. Burlington, 800 MW
3. Lamar, 400 MW
4. Big Sandy, 400 MW & Lamar, 400 MW

An ATT scenario was considered that added +25% line compensation to the Big Sandy – Windtalker 230 kV line to validate if ATT could increase injection under the Burlington injection location scenario.

Table 67: Story, 800 MW Injection

Element	Contingency	Maximum Injection
Smoky Hill – Missile Site 345	P7: Tundra – May 345 1 & 2 Missile Site – Daniels Park 345	480MW (0 MW)

Table 68: Burlington, 800 MW Injection

Element	Contingency	Maximum Injection
Big Sandy – Windtalker 230	Story – Burlington Satellite 345	560 MW
Burlington – Bonny Creek – South Fork 115	Story – Burlington Satellite 345	640 MW
N. Yuma – Story 230	Story – Burlington Satellite 345	640 MW
Burlington – Burlington Satellite 230	Story – Burlington Satellite 345	720 MW

Table 69: Lamar, 400 MW Injection

Element	Contingency	Maximum Injection
Lamar – Willow Creek 115	Lamar – Burlington Satellite 345	280 MW
Boone – Lamar 230	Lamar – Burlington Satellite 345	320 MW
--- Non Converged ---	Lamar – Burlington Satellite 345	>360 MW

Table 70: Burlington, 400 MW Injection & Lamar, 400 MW Injection

Element	Contingency	Maximum Injection
Lamar – Willow Creek 115	Lamar – Burlington Satellite 345	560 MW
Vilas 115/69 T1	Willow Creek – Lamar 115	560 MW
Boone – Lamar 230	Lamar – Burlington Satellite 345	640 MW
Big Sandy – Windtalker 230	Story – Burlington Satellite 345	640 MW
Burlington – Bonny Creek – South Fork 115	Story – Burlington Satellite 345	720 MW
N. Yuma – Story 230	Story – Burlington Satellite 345	720 MW
--- Non Converged ---	Lamar – Burlington Satellite 345	720 MW

Table 71: Burlington, 800 MW Injection (ATT)

Element	Contingency	Maximum Injection
Big Sandy – Windtalker 230	Story – Burlington Satellite 345	640 MW (560 MW)
Burlington – Bonny Creek – South Fork 115	Story – Burlington Satellite 345	640 MW
N. Yuma – Story 230	Story – Burlington Satellite 345	640 MW
Burlington – Burlington Satellite 230	Story – Burlington Satellite 345	720 MW

B. Summary

Alternative 3 showed no negative interactions with the proposed CPP Project. The Story injection node showed increased injection capability of approximately

480 MW due to the proposed CPP Project. This increase in injection capability is attributed to the additional transmission between Pawnee and Fort St Vrain. No increases in injection capability were observed at Burlington or Lamar. The use of ATT (power flow control, +25% line compensation) showed an ability to enhance injection capability by approximately 80 MW for the scenario studied.

12.2 Alternative 4 Sensitivity Analysis

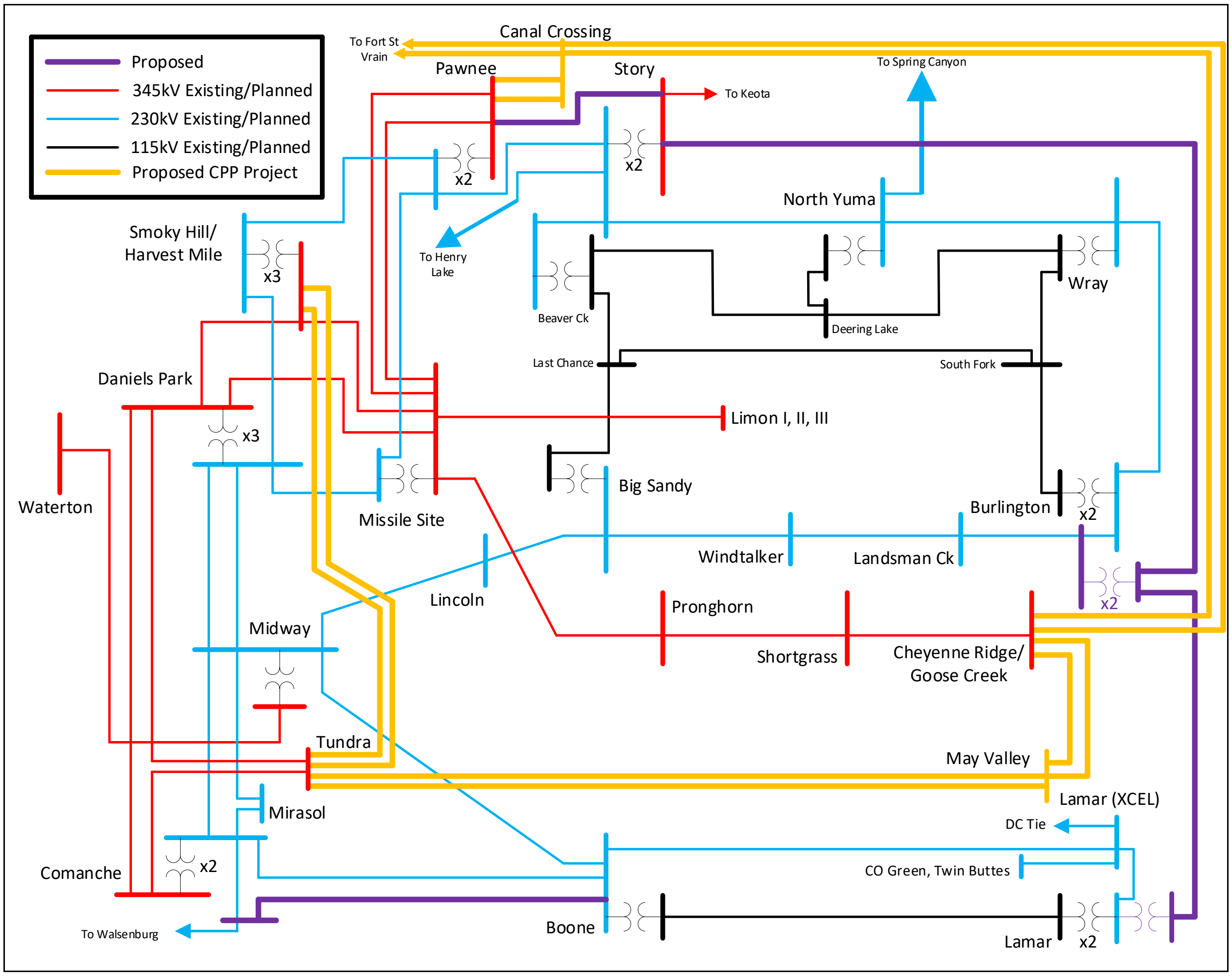

Figure 18: Alternative 4 w/ proposed CPP Project

A. Study Results

Generation was individually injected into the following locations:

1. Story, 800 MW
2. Burlington, 800 MW
3. Lamar, 800 MW

An ATT scenario was considered that added +25% line compensation to the Big Sandy – Windtalker 230 kV line to validate if ATT could increase injection under the Burlington injection location scenario.

Table 72: Story, 800 MW Injection

Element	Contingency	Maximum Injection
Smoky Hill – Missile Site 345	P7: Tundra – May 345 1 & 2 Missile Site – Daniels Park 345	640 MW (0 MW)

Table 73: Burlington, 800 MW Injection

Element	Contingency	Maximum Injection
Big Sandy – Windtalker 230	Story – Burlington Satellite 345	560 MW
N. Yuma – Story 230	Story – Burlington Satellite 345	640 MW
Burlington – Bonny Creek – South Fork 115	Story – Burlington Satellite 345	640 MW
Burlington – Burlington Satellite 230	Story – Burlington Satellite 345	720 MW

Table 74: Lamar, 800 MW Injection

Element	Contingency	Maximum Injection
Lamar – Willow Creek 115	Lamar – Burlington Satellite 345	280 MW
Boone – Lamar 230	Lamar – Burlington Satellite 345	320 MW
--- Non Converged ---	Lamar – Burlington Satellite 345	>360 MW

Table 75: Burlington, 400 MW Injection & Lamar, 400 MW Injection

Element	Contingency	Maximum Injection
Lamar – Willow Creek 115	Lamar – Burlington Satellite 345	560 MW
Vilas 115/69 T1	Willow Creek – Lamar 115	640 MW
Boone – Lamar 230	Lamar – Burlington Satellite 345	640 MW
Big Sandy – Windtalker 230	Story – Burlington Satellite 345	640 MW
Burlington – Bonny Creek – South Fork 115	Story – Burlington Satellite 345	720 MW
N. Yuma – Story 230	Story – Burlington Satellite 345	720 MW
--- Non Converged ---	Lamar – Burlington Satellite 345	720 MW

Table 76: Burlington, 800 MW Injection (ATT)

Element	Contingency	Maximum Injection
Big Sandy – Windtalker 230	Story – Burlington Satellite 345	640 MW (560 MW)
Burlington – Bonny Creek – South Fork 115	Story – Burlington Satellite 345	640 MW
N. Yuma – Story 230	Story – Burlington Satellite 345	720 MW (640 MW)
Burlington – Burlington Satellite 230	Story – Burlington Satellite 345	720 MW

B. Summary

Alternative 4 showed no negative interactions with the proposed CPP Project. The Story injection node showed increased injection capability of approximately 640 MW due to the proposed CPP Project. This increase in injection capability is attributed to the additional transmission between Pawnee and Fort St Vrain. No increases in injection capability were observed at Burlington or Lamar. The use of ATT (power flow control, +25% line compensation) showed an ability to enhance injection capability by approximately 80 MW for the scenario studied.

12.3 Alternative 5 Sensitivity Analysis

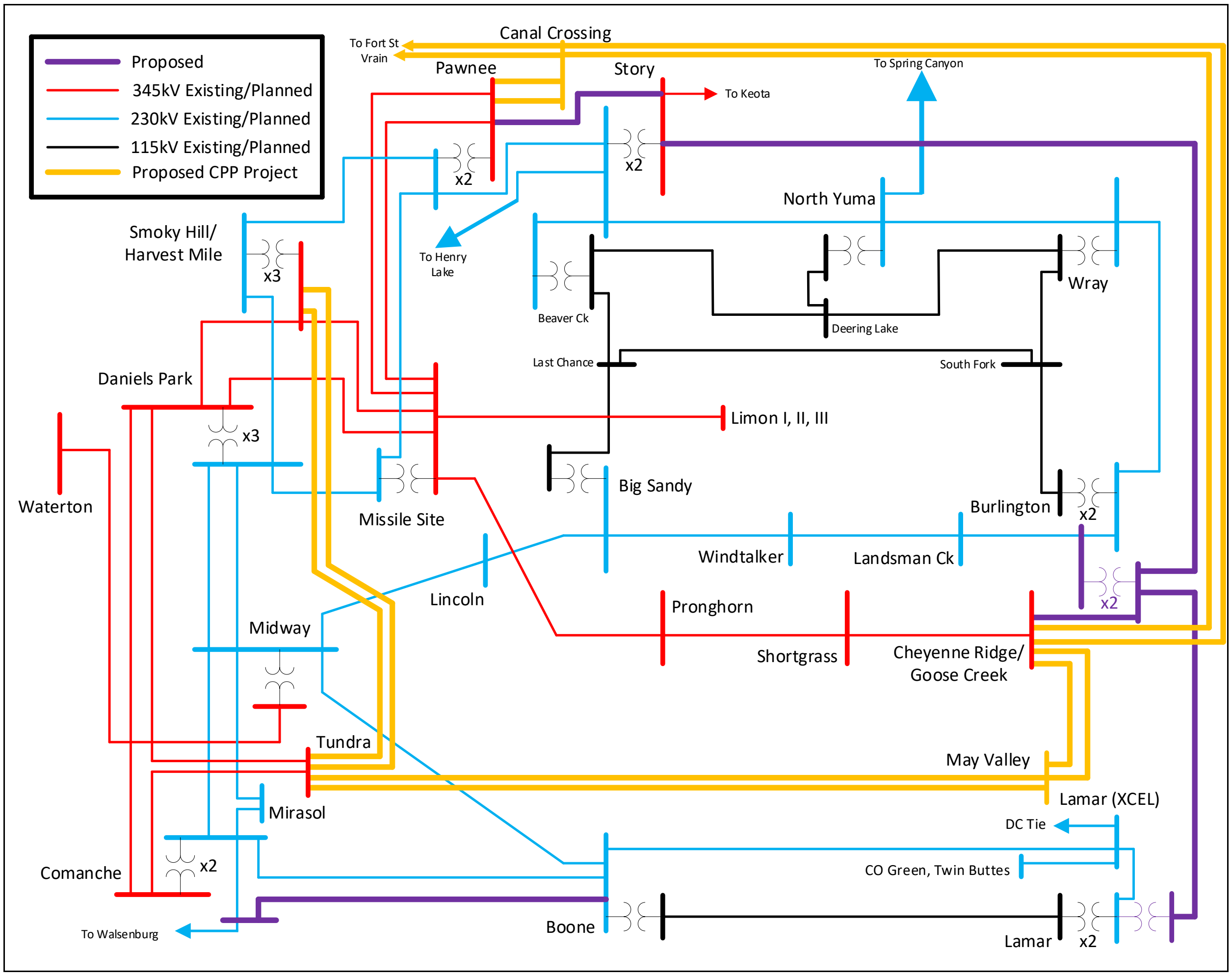

Figure 19: Alternative 5 w/ proposed CPP Project

A. Study Results

Generation was individually injected into the following locations:

1. Story, 800 MW
2. Burlington, 800 MW
3. Lamar, 400 MW
4. Burlington, 400 MW & Lamar, 400 MW

Table 77: Story, 800 MW Injection

Element	Contingency	Maximum Injection
Smoky Hill – Missile Site 345	Missile Site – Daniels Park 345	>800 MW (80 MW)

Table 78: Burlington, 800 MW Injection

Element	Contingency	Maximum Injection
Big Sandy – Windtalker 230	Missile Site - Pronghorn 345	>800 MW (400 MW)
Missile Site – Smoky Hill 345	Missile Site – Daniels Park 345	>800 MW (640 MW)
Burlington – Bonny Creek – South Fork 115	Missile Site - Pronghorn 345	>800 MW (640 MW)
Lamar – Willow Creek 115	Missile Site - Pronghorn 345	>800 MW (640 MW)
Burlington – Burlington Satellite 230	Missile Site - Pronghorn 345	>800 MW (720 MW)

Table 79: Lamar, 400 MW Injection

Element	Contingency	Maximum Injection
Lamar – Willow Creek 115	Lamar – Burlington Satellite 345	320 MW
Boone – Lamar 230	Lamar – Burlington Satellite 345	320 MW
Vilas 115/69 T1	Willow Creek – Lamar 115	320 MW
--- Non Converged ---	Lamar – Burlington Satellite 345	>400 MW

Table 80: Burlington, 400 MW Injection & Lamar, 400 MW Injection

Element	Contingency	Maximum Injection
Big Sandy – Windtalker 230	Missile Site - Pronghorn 345	>800 MW (480 MW)
Vilas 115/69 T1	Willow Creek – Lamar 115	480 MW
Lamar – Willow Creek 115	Lamar – Burlington Satellite 345	560 MW
Boone – Lamar 230	Lamar – Burlington Satellite 345	640 MW
Burlington – Bonny Creek – South Fork 115	Story – Burlington Satellite 345	720 MW
--- Non Converged ---	Lamar – Burlington Satellite 345	720 MW

B. Summary

Alternative 5 showed no negative interactions with the proposed CPP Project. The Story and Burlington injections node showed increased injection capability of over 720 MW and 400 MW, respectively, due to the proposed CPP Project. This increase in injection capability is attributed to the leveraging the proposed CPP Project transmission elements. No increases in injection capability were observed at Lamar.

12.4 Alternative 6B Sensitivity Analysis

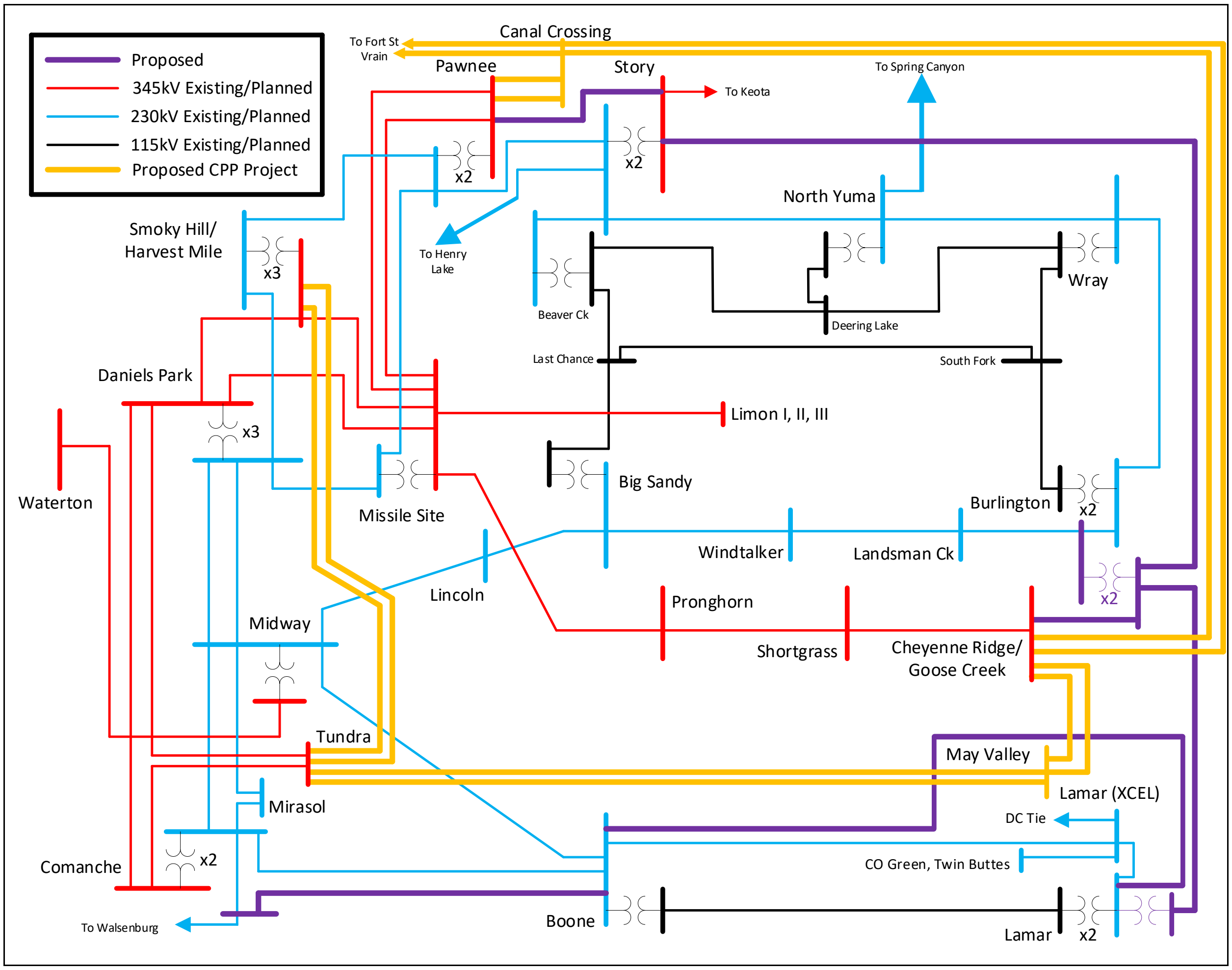

Figure 20: Alternative 6B w/ proposed CPP Project

A. Study Results

Generation was individually injected into the following locations:

1. Story, 800 MW
2. Burlington, 1500 MW
3. Lamar, 800 MW
4. Burlington, 800 MW & Lamar, 800 MW

Table 81: Story, 800 MW Injection

Element	Contingency	Maximum Injection
--- Smoky Hill – Missile Site 345	--- Missile Site – Daniels Park 345	>800 MW (240 MW)

Table 82: Burlington, 1500 MW Injection

Element	Contingency	Maximum Injection
Eckley – North Yuma Tap – Deering Lake 115 Big Sandy – Windtalker 230	North Yuma – Wray 230 Missile Site – Pronghorn 345	1350 MW (640 MW)

Table 83: Lamar, 800 MW Injection

Element	Contingency	Maximum Injection
Vilas 115/69 T1	Lamar – Willow Creek 115	720 MW

Table 84: Burlington, 800 MW Injection & Lamar, 800 MW Injection

Element	Contingency	Maximum Injection
Vilas 115/69 T1 Big Sandy – Windtalker 230	Lamar – Willow Creek 115 Missile Site – Pronghorn 345	1120 MW (800 MW)

B. Summary

Alternative 6B showed no negative interactions with the proposed CPP Project. The Story and Burlington injections node showed increased injection capability of over 560 MW and 710 MW, respectively, due to the proposed CPP Project. This increase in injection capability is attributed to the leveraging the proposed CPP Project transmission elements. No increases in injection capability were observed at Lamar.

12.5 Alternative 7 Sensitivity Analysis

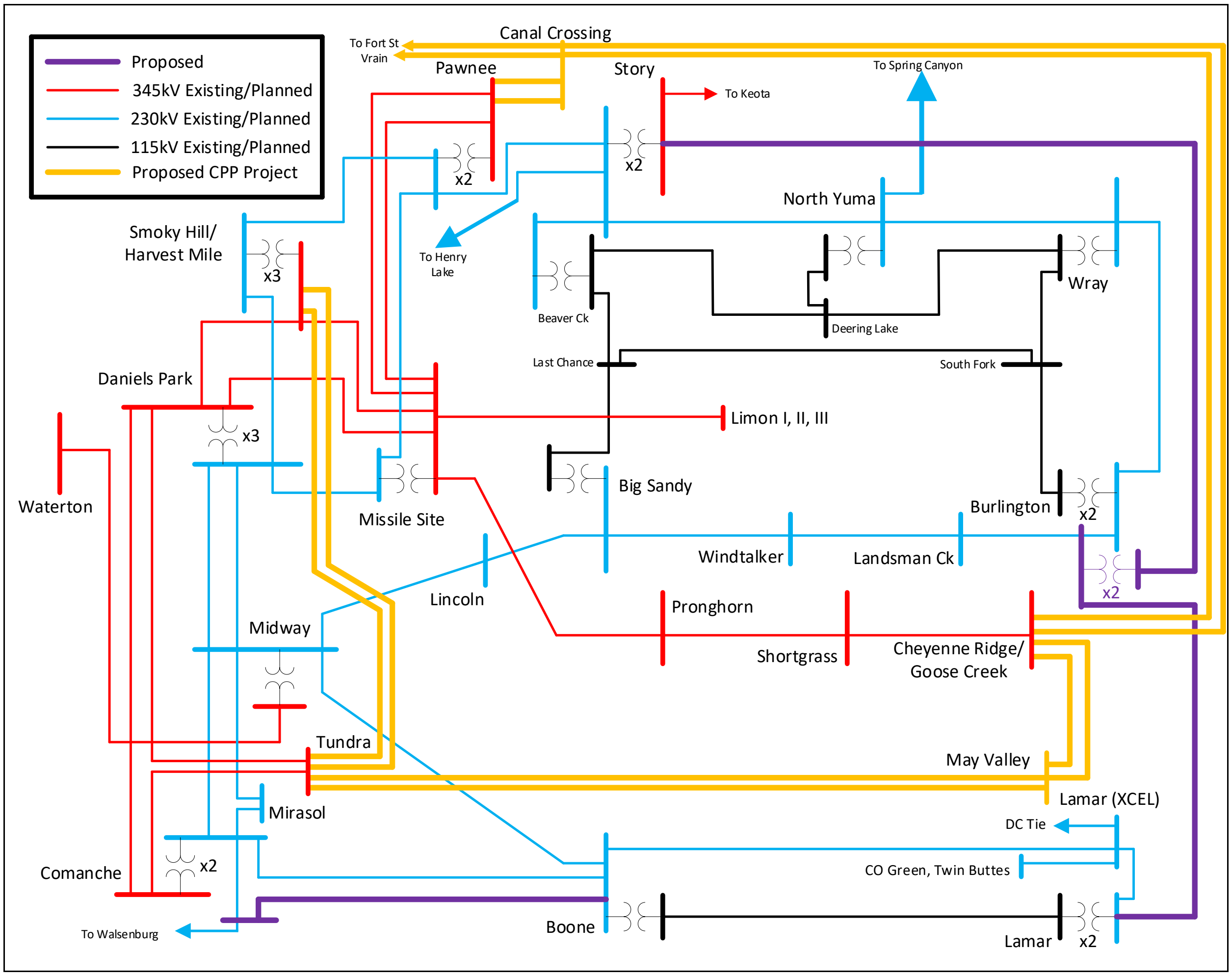

Figure 21: Alternative 7 w/ proposed CPP Project

A. Study Results

Generation was individually injected into the following locations:

1. Story, 800 MW
2. Burlington, 800 MW
3. Lamar, 400 MW
4. Burlington, 400 MW & Lamar, 400 MW

An ATT scenario was considered that added +25% line compensation to the Big Sandy – Windtalker 230 kV line to validate if ATT could increase injection under the Burlington injection location scenario.

Table 85: Story, 800 MW Injection

Element	Contingency	Maximum Injection
Smoky Hill – Missile Site 345	P7: Tundra – May 345 1 & 2 Missile Site – Daniels Park 345	480 MW (0 MW)

Table 86: Burlington, 800 MW Injection

Element	Contingency	Maximum Injection
Big Sandy – Windtalker 230	Story – Burlington Satellite 345	560 MW
Burlington – Bonny Creek – South Fork 115	Story – Burlington Satellite 345	560 MW
N. Yuma – Story 230	Story – Burlington Satellite 345	560 MW
N. Yuma – Wray 230	Story – Burlington Satellite 345	720 MW
Deering Lake – E. Yuma – Eckley 115	Story – Burlington Satellite 345	720 MW

Table 87: Lamar, 400 MW Injection

Element	Contingency	Maximum Injection
Vilas 115/69 T1	Willow Creek – Lamar 115	240 MW
Lamar – Willow Creek 115	Lamar – Burlington Satellite 230	280 MW
Boone – Lamar 230	Lamar – Burlington Satellite 230	320 MW
--- Non Converged ---	Lamar – Burlington Satellite 230	>360 MW

Table 88: Burlington, 400 MW Injection & Lamar, 400 MW Injection

Element	Contingency	Maximum Injection
Vilas 115/69 T1	Willow Creek – Lamar 115	320 MW
Lamar – Willow Creek 115	Lamar – Burlington Satellite 230	320 MW
Boone – Lamar 230	Lamar – Burlington Satellite 230	320 MW
Willow Creek – Lamso – La Junta 115	Lamar – Boone 230	560 MW
Big Sandy – Windtalker 230	Story – Burlington Satellite 345	720 MW
Burlington – Bonny Creek – South Fork 115	Story – Burlington Satellite 345	720 MW
N. Yuma – Story 230	Story – Burlington Satellite 345	720 MW

Table 89: Burlington, 800 MW Injection (ATT)

Element	Contingency	Maximum Injection
Big Sandy – Windtalker 230	Story – Burlington Satellite 345	560 MW
Burlington – Bonny Creek – South Fork 115	Story – Burlington Satellite 345	560 MW
N. Yuma – Story 230	Story – Burlington Satellite 345	560 MW
N. Yuma – Wray 230	Story – Burlington Satellite 345	720 MW
Deering Lake – E. Yuma – Eckley 115	Story – Burlington Satellite 345	720 MW

B. Summary

Alternative 7 showed no negative interactions with the proposed CPP Project. The Story injection node showed increased injection capability of approximately 480 MW due to the proposed CPP Project. This increase in injection capability is attributed to the additional transmission between Pawnee and Fort St Vrain. No increases in injection capability were observed at Burlington or Lamar. The use of ATT (power flow control, +25% line compensation) did not show an ability to enhance injection capability for the scenario studied.

12.6 Alternative 8 Sensitivity Analysis

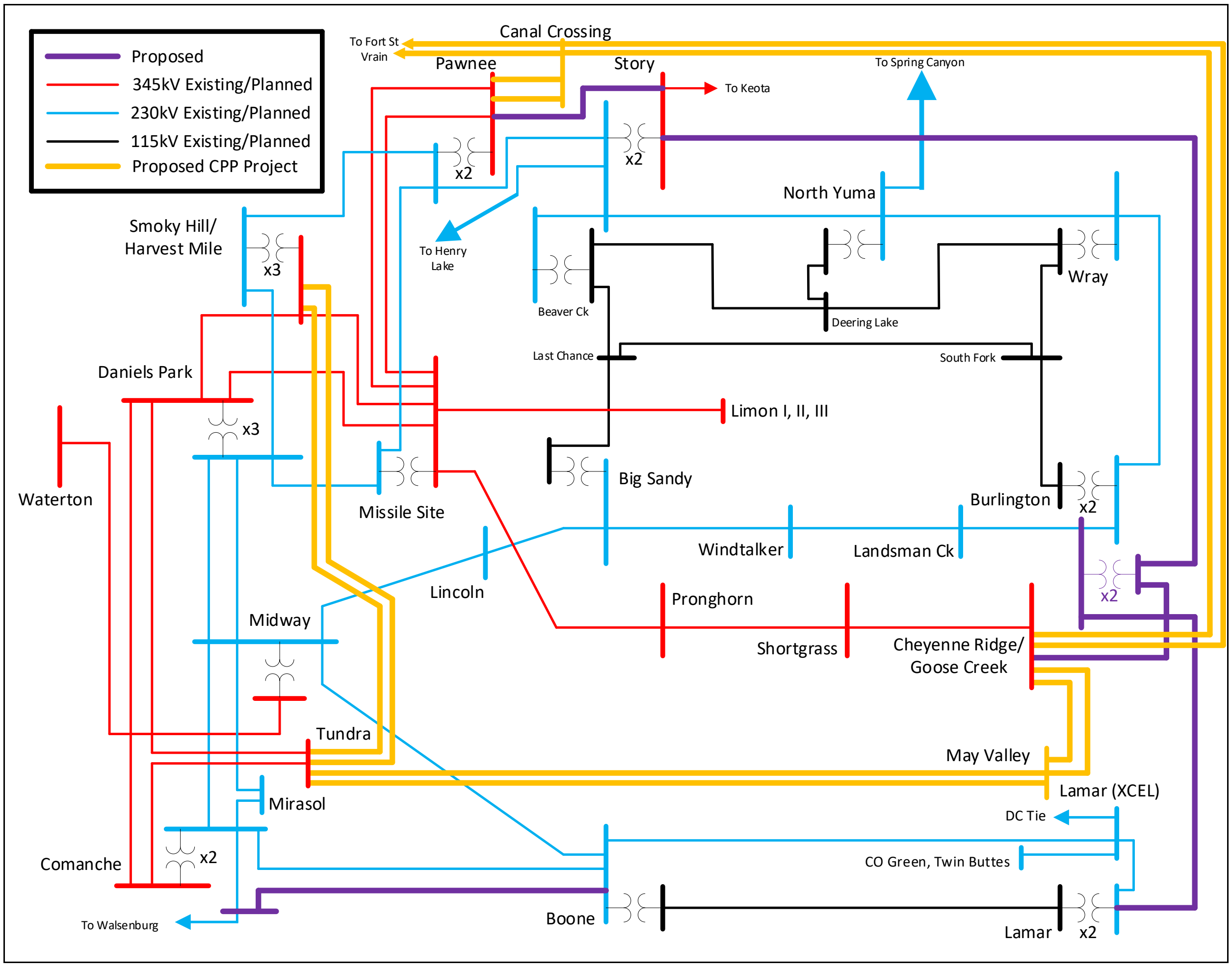

Figure 22: Alternative 8 w/ proposed CPP Project

A. Study Results

Generation was individually injected into the following locations:

1. Story, 800 MW
2. Burlington, 800 MW
3. Lamar, 400 MW
4. Burlington, 400 MW & Lamar, 400 MW

115847628.1

Table 90: Story, 800 MW Injection

Element	Contingency	Maximum Injection
Smoky Hill – Missile Site 345	--- Missile Site – Daniels Park 345	>800 MW (80 MW)

Table 91: Burlington, 800 MW Injection

Element	Contingency	Maximum Injection
Big Sandy – Windtalker 230	--- Missile Site – Pronghorn 345	>800 MW (400 MW)
Burlington – Bonny Creek – South Fork 115	--- Missile Site – Pronghorn 345	>800 MW (560 MW)
Missile Site – Smoky Hill 345	--- Missile Site – Daniels Park 345	>800 MW (640 MW)
--- Non Converged ---	--- Missile Site – Pronghorn 345	>800 MW (>640 MW)

Table 92: Lamar, 400 MW Injection

Element	Contingency	Maximum Injection
Vilas 115/69 T1	Willow Creek – Lamar 115	160 MW
Lamar – Willow Creek 115	Lamar – Burlington Satellite 230	280 MW
Boone – Lamar 230	Lamar – Burlington Satellite 230	320 MW
--- Non Converged ---	Lamar – Burlington Satellite 230	>360 MW

Table 93: Burlington, 400 MW Injection & Lamar, 400 MW Injection

Element	Contingency	Maximum Injection
Vilas 115/69 T1	Willow Creek – Lamar 115	320 MW
Big Sandy – Windtalker 230	Missile Site – Pronghorn 345	>800 MW (480 MW)
Lamar – Willow Creek 115	Lamar – Burlington Satellite 230	560 MW
Boone – Lamar 230	Lamar – Burlington Satellite 230	640 MW
Burlington – Bonny Creek – South Fork 115	Missile Site – Pronghorn 345	720 MW
--- Non Converged ---	Lamar – Burlington Satellite 230	>720 MW

B. Summary

Alternative 8 showed no negative interactions with the proposed CPP Project. The Story and Burlington injections node showed increased injection capability of over 720 MW and 400 MW, respectively, due to the proposed CPP Project. This increase in injection capability is attributed to the leveraging the proposed CPP Project transmission elements. No increases in injection capability were observed at Lamar.

12.7 Alternative 14 Sensitivity Analysis

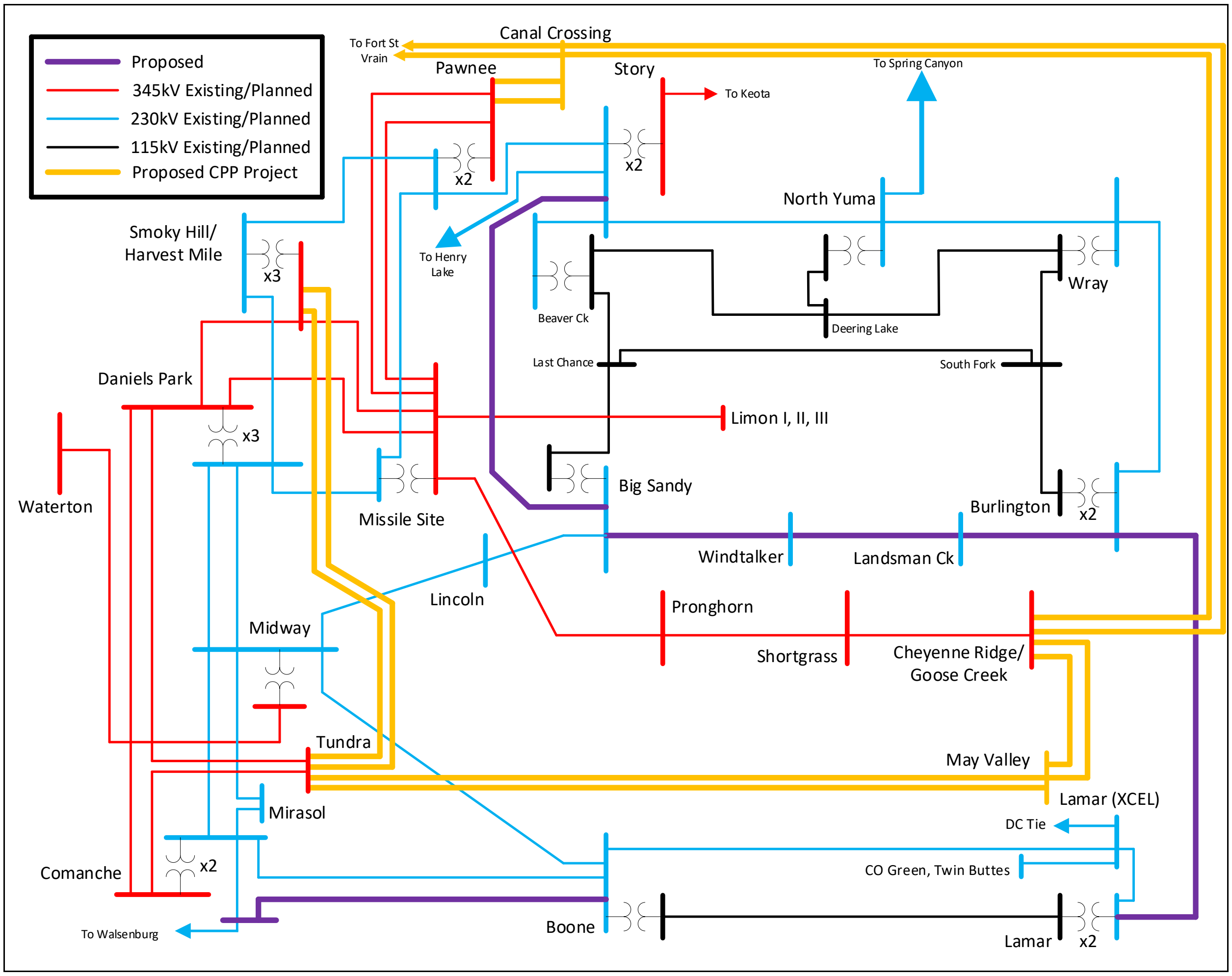

Figure 23: Alternative 14 w/ proposed CPP Project

A. Study Results

Generation was individually injected into the following locations:

1. Story, 400 MW
2. Burlington, 400 MW
3. Lamar, 400 MW
4. Big Sandy, 800 MW
5. Big Sandy, 400 MW & Lamar, 400 MW

An ATT scenario was considered that added +25% line compensation to Big Sandy – Last Chance 115 kV and -25% line compensation to Burlington – Bonny Creek – South Fork 115 kV to validate if ATT could increase injection under the Big Sandy injection location scenario.

Table 94: Story, 400 MW Injection

Element	Contingency	Maximum Injection
Smoky Hill – Missile Site 345	--- Missile Site – Daniels Park 345	>800 MW (0 MW)

Table 95: Burlington, 400 MW Injection

Element	Contingency	Maximum Injection
South Fork – Joes – Last Chance 115	Big Sandy – Windtalker 230	160 MW
Deering Lake – E. Yuma – Eckley 115	Wray – N. Yuma 230	200 MW
Burlington – Bonny Creek – South Fork 115	Burlington – Wray 230	200 MW
N. Yuma – Story 230	Big Sandy – Windtalker 230	240 MW
Deering Lake – Akron – Beaver Creek 115	N. Yuma – Story 230	280 MW

Table 96: Lamar, 400 MW Injection

Element	Contingency	Maximum Injection
Vilas 115/69 T1	Lamar – Willow Creek 115	160 MW
South Fork – Joes – Last Chance 115	Big Sandy – Windtalker 230	280 MW
Lamar – Willow Creek 115	Burlington – Lamar 230	280 MW
Boone – Lamar 230	Burlington – Lamar 230	320 MW
Deering Lake – E. Yuma – Eckley 115	Wray – N. Yuma 230	360 MW
Burlington – Bonny Creek – South Fork 115	Burlington – Wray 230	360 MW

Table 97: Big Sandy, 800 MW Injection

Element	Contingency	Maximum Injection
Big Sandy – Last Chance 115	Big Sandy – Story 230	560 MW

Table 98: Lamar, 400 MW Injection & Big Sandy, 400 MW

Element	Contingency	Maximum Injection
Vilas 115/69 T1	Lamar – Willow Creek 115	240 MW
Deering Lake – E. Yuma – Eckley 115	Wray – N. Yuma 230	480 MW
Burlington – Bonny Creek – South Fork 115	Burlington – Wray 230	560 MW
Lamar – Willow Creek 115	Burlington – Lamar 230	560 MW
Boone – Lamar 230	Burlington – Lamar 230	>800 MW (640 MW)
Big Sandy – L. Chance – Woodrow – Beaver Ck 115	Big Sandy – Story 230	720 MW
Deering Lake – Akron – Beaver Creek 115	N. Yuma – Story 230	720 MW

Table 99: Big Sandy, 800 MW Injection (ATT)

Element	Contingency	Maximum Injection
Big Sandy – Last Chance 115	Big Sandy – Story 230	560 MW
Big Sandy – Story 230	Lincoln – Midway 230	560 MW

B. Summary

Alternative 14 showed no negative interactions with the proposed CPP Project. The Story injection node showed increased injection capability of approximately 800 MW due to the proposed CPP Project. This increase in injection capability is attributed to the additional transmission between Pawnee and Fort St Vrain. No increases in injection capability were observed at Burlington or Lamar. The use of ATT (power flow control, +25% and -25% line compensation) did not show an ability to enhance injection capability for the scenario studied.

12.8 Sensitivity Results Summary

Select REPTF alternatives (3, 4, 5, 6B, 7, 8, and 14) were evaluated to determine the potential impact on the proposed CPP Project, as well as the potential impact to the select alternative by the proposed CPP Project. The sensitivity analysis performed resulted in the following observations:

1. The REPTF alternatives showed no negative interactions with the proposed CPP Project.
2. The proposed CPP Project improved injection capability at Story in all alternatives and at Burlington in three alternatives (5, 6B, and 8), and had no impact on injection capability at Lamar in all alternatives.
3. The utilization of ATT (power flow control) showed the potential to enhance injection capability.

However, the increased injection capability observed at Story and Burlington is not an accurate reflection of additional resources (injection capability) accommodated by the proposed CPP Project. This is due to the geographically diverse dispatch (not severely stressed) utilized on the proposed CPP Project due to unknown new resource size/locations, and associated reactive support or grid enforcements technologies that may be required/constructed. Rather, the increased injection capability represents the ability of REPTF alternatives to leverage an unstressed proposed CPP project.

13.0 CONCLUSIONS

The results of the study indicate that several alternatives are capable of accommodating at least 400 MW of new generation in eastern Colorado, providing connectivity across Tri-State's four-state service area, improving transmission system reliability in the Lamar area, and reducing generation curtailment in eastern Colorado under 230 kV prior outage conditions. The most efficient, cost-effective alternatives to meet the objectives and needs were Alternatives 7 and 14. The most efficient, cost-effective alternative to meet the needs of multiple Colorado utilities was Alternative 6, albeit at a cost of over $1 billion. Alternative 6 would provide an option for other Transmission Providers, who choose to participate, to utilize a portion of the project to meet their de-carbonization goals/needs. Alternatives 3, 4, 5, 6B, and 8 were shown to be capable alternatives, but at a higher cost or less efficient use of capital if pursued. Some stakeholders believe the long-term reliability and system benefits provided by increased transmission connections and 345 kV construction make the expanded alternatives (4, 5, 6, 6B, and 8) worthy of consideration today. ATT/NWA alone does not meet the objectives and needs.

The analysis included an evaluation of transmission system performance utilizing applicable reliability criteria, and sensitivity studies with the proposed CPP Project and ATT (power flow control). Sensitivity analyses demonstrated:

1. The REPTF alternatives showed no negative interactions with the proposed CPP Project.

2. The proposed CPP Project benefited injection capability at Story in all alternatives and at Burlington in three alternatives (5, 6B, and 8), and had no impact on injection capability at Lamar in all alternatives.
3. The utilization of ATT (power flow control) showed the potential to enhance injection capability.

However, the increased injection capability observed at Story and Burlington is not an accurate reflection of additional resources accommodated by the proposed CPP Project. This is due to the geographically diverse dispatch (not severely stressed) utilized on the proposed CPP Project due to unknown new resource size/locations, and associated reactive support or grid enforcements technologies that may be required/constructed. Rather, the increased injection capability represents the ability of REPTF alternatives to leverage an unstressed proposed CPP project.

Each of the alternatives evaluated would meet multiple objectives and needs, and would significantly improve the reliability of the eastern Colorado transmission network by providing additional transmission infrastructure to the Burlington and Lamar areas. In terms of overall system reliability, including multiple connections between transmission systems and between the eastern Colorado transmission system and the Front Range load centers provides a more robust transmission system. However, this is can only be accomplished at an increased financial cost. No single alternative was identified as preferred due to numerous considerations that the REPTF agreed should be taken into account, such as cost, participation, existing needs, and future needs.

APPENDIX A: Stakeholders

Name	Entity
Ryan Sherlock	Avangrid
Shawn Carlson	Basin Electric
Lindsay Briggs	Black Hills
Tyler Cooper	Black Hills
Todd Kuhn	Black Hills
Trevor Rombough	Black Hills
Puneet Pasrich	Buckyball Systems
Joel Eggemeyer	Colorado Springs Utilities
Matt Israel	Colorado Springs Utilities
K.C. Cunilio	Dietze and Davis, P.C.
Mark Detsky	Dietze and Davis, P.C.
Matt Jacobs	Enel Green Power
Gimod Olapurayil	Enel Green Power
Arthur Roden	Enel Green Power
Kavita Shenoi	Energy Strategies
Sina Baghsorkhi	Grid Numerics/Juwi
Carl Huslig	Grid Resiliency Consulting
Jay Caspary	Grid Strategies
Larry Miloshevich	Independent
Lisa Hickey	Interwest Energy Alliance
Isaac Kort-Meade	Interwest Energy Alliance
Chris Leger	Interwest Energy Alliance
Orijit Ghoshal	Invenergy
Ajay Pappu	Invenergy
Ben Turner	Invenergy
John Wolfe	Invenergy
Matt Russell	National Renewable Solutions
Alan Comes	New Energy Consulting
Charles Cheung	NextEra Energy
John Dailey	NextEra Energy
Tricia Hale	NextEra Energy
Jennifer Herron	NextEra Energy
Nathan Kesier	NextEra Energy
Taylor Henderson	Outshine Energy
Jeremy Brownrigg	Platte River Power Authority
Giancarlo Leone	SR3 Engineering
Adam Gribb	State of Colorado
Dan Greenberg	State of Colorado

Chris Neil	State of Colorado
Keith Carman	Tri-State G&T
Dylan Fate	Tri-State G&T
Curt Feinberg	Tri-State G&T
Chris Gilden	Tri-State G&T
David Gustad	Tri-State G&T
Ryan Hubbard	Tri-State G&T
Susan Hunter	Tri-State G&T
Kevin Lindquist	Tri-State G&T
Laura Marino	Tri-State G&T
Jeff Milius	Tri-State G&T
Jared Nelson	Tri-State G&T
Chris Pink	Tri-State G&T
John Reasoner	Tri-State G&T
Paul Scrivens	Tri-State G&T
Cody Sickler	Tri-State G&T
Ken Wilson	Western Resource Advocates
Patrick Corrigan	Xcel Energy
Gilbert Flores	Xcel Energy
James Nguyen	Xcel Energy
Connie Paoletti	Xcel Energy
Hari Singh	Xcel Energy

APPENDIX B: Benchmark Generation Dispatch

Heavy Summer Case

BUS	GENERATOR	UNIT	STATUS	PGen	PMax
70010	TBII_GEN 0.6900	W	1	70.2	78
70069	CABCRKA 13.800	HA	1	160	162
70070	CABCRKB 13.800	HB	1	160.38	162
70104	CHEROK2 15.500	SC	1	0	0
70106	CHEROK4 22.000	G4	1	360	335
70145	CHEROKEE5 18.000	G5	1	170	182
70146	CHEROKEE6 18.000	G6	1	170	182
70147	CHEROKEE7 18.000	ST	1	220	248
70188	FTLUP1-2 13.800	G1	1	40	50
70188	FTLUP1-2 13.800	G2	1	40	50
70310	PAWNEE 22.000	C1	1	460.8896	536
70314	MANCHEF1 16.000	G1	1	120	140
70315	MANCHEF2 16.000	G2	1	120	140
70408	ST.VR_4 18.000	G4	1	140	143
70409	ST.VRAIN 22.000	ST	1	300	312
70487	JMSHAFR4 13.800	G4	1	34.8	34.8
70487	JMSHAFR4 13.800	G5	1	33	33
70490	JMSHAFR3 13.800	G3	1	36.1	36.1
70490	JMSHAFR3 13.800	ST	1	50	50
70493	JMSHAFR2 13.800	ST	1	26.2	50.7
70495	JMSHAFR1 13.800	G1	1	35.8	35.8
70495	JMSHAFR1 13.800	G2	1	35	35
70498	QF_BCP2T 13.800	G3	1	20	34.1
70498	QF_BCP2T 13.800	ST	1	20	36
70499	QF_B4-4T 13.800	G4	1	8	24
70500	QF_CPP1T 13.800	G1	1	13.5	24
70500	QF_CPP1T 13.800	G2	1	13.2	24
70501	QF_CPP3T 13.800	ST	1	15	27
70502	PIONEER_IR_S34.500	S1	1	52	80
70553	ARAP5&6 13.800	G5	1	38	39
70553	ARAP5&6 13.800	G6	1	38	39.5
70554	ARAP7 13.800	ST	1	43	47
70557	VALMNT7 13.800	G7	1	35	41.7
70558	VALMNT8 13.800	G8	1	35	41.7
70562	SPRUCE1 18.000	G1	1	130	145.1
70563	SPRUCE2 18.000	G2	1	130	140.5

70565	KNUTSON1 13.800	G1	1	67.5	72.5
70566	KNUTSON2 13.800	G2	1	40	72.5
70572	KIOWA_IR_S 34.500	S1	1	35.425	54.5
70577	FTNVL1&2 13.800	G1	1	40	40
70577	FTNVL1&2 13.800	G2	1	40	40
70578	FTNVL3&4 13.800	G3	1	40	40
70578	FTNVL3&4 13.800	G4	1	40	40
70579	FTNVL5&6 13.800	G5	1	40	40
70579	FTNVL5&6 13.800	G6	1	40	40
70580	PLNENDG1_1 13.800	G0	1	5	5.4
70580	PLNENDG1_1 13.800	G1	1	5	5.4
70580	PLNENDG1_1 13.800	G2	1	5	5.4
70580	PLNENDG1_1 13.800	G3	1	5	5.4
70580	PLNENDG1_1 13.800	G4	1	5	5.4
70580	PLNENDG1_1 13.800	G5	1	5	5.4
70580	PLNENDG1_1 13.800	G6	1	5	5.4
70580	PLNENDG1_1 13.800	G7	1	5	5.4
70580	PLNENDG1_1 13.800	G8	1	5	5.4
70580	PLNENDG1_1 13.800	G9	1	5	5.4
70585	PLNENDG2_1 13.800	G1	1	8	8.1
70585	PLNENDG2_1 13.800	G2	1	8	8.1
70585	PLNENDG2_1 13.800	G3	1	8	8.1
70585	PLNENDG2_1 13.800	G4	1	8	8.1
70585	PLNENDG2_1 13.800	G5	1	8	8.1
70585	PLNENDG2_1 13.800	G6	1	8	8.1
70585	PLNENDG2_1 13.800	G7	1	8	8.1
70586	PLNENDG2_2 13.800	G1	1	8	8.1
70586	PLNENDG2_2 13.800	G2	1	8	8.1
70586	PLNENDG2_2 13.800	G3	1	8	8.1
70586	PLNENDG2_2 13.800	G4	1	8	8.1
70586	PLNENDG2_2 13.800	G5	1	8	8.1
70586	PLNENDG2_2 13.800	G6	1	8	8.1
70586	PLNENDG2_2 13.800	G7	1	8	8.1
70587	PLNENDG1_2 13.800	G0	1	5	5.4
70587	PLNENDG1_2 13.800	G1	1	5	5.4
70587	PLNENDG1_2 13.800	G2	1	5	5.4
70587	PLNENDG1_2 13.800	G3	1	5	5.4
70587	PLNENDG1_2 13.800	G4	1	5	5.4
70587	PLNENDG1_2 13.800	G5	1	5	5.4
70587	PLNENDG1_2 13.800	G6	1	5	5.4

70587	PLNENDG1_2 13.800	G7	1	5	5.4
70587	PLNENDG1_2 13.800	G8	1	5	5.4
70587	PLNENDG1_2 13.800	G9	1	5	5.4
70588	RMEC1 15.000	G1	1	150	159
70589	RMEC2 15.000	G2	1	150	159
70591	RMEC3 23.000	ST	1	300	303
70593	SPNDLE1 18.000	G1	1	130	143.07
70594	SPNDLE2 18.000	G2	1	130	140.59
70616	TITAN_S1 0.6300	S1	1	32.5	53.55
70629	RUSHCK_W1 34.500	W1	1	150	380
70631	RUSHCK_W2 34.500	W2	1	120	220
70635	LIMON1_W 34.500	W1	1	100	201
70636	LIMON2_W 34.500	W2	1	100	201
70637	LIMON3_W 34.500	W3	1	100	201
70665	GLDNWST_W1 0.6900	W1	1	26.06	124.1
70666	GLDNWST_W2 0.6900	W2	1	26.42	125
70670	CEDARPT_W1 0.6900	W1	1	26	124.2
70671	CEDARPT_W2 0.6900	W2	1	26.46	126
70701	CO_GRN_E 34.500	W1	1	73.2	81
70702	CO_GRN_W 34.500	W2	1	73.2	81
70703	TWNBUTTE 34.500	W1	1	68	75
70710	PTZLOGN1 34.500	W1	1	42.21	201
70712	PTZLOGN2 34.500	W2	1	25.2	120
70713	PTZLOGN3 34.500	W3	1	16.7	79.5
70714	PTZLOGN4 34.500	W4	1	36.8	175
70721	SPRNGCAN1_W10.5700	W1	1	59	64.8
70723	RDGCREST 34.500	W1	1	6.24	29.7
70733	CHEYRGE_W1 0.6900	W1	1	26.04	124
70736	CHEYRGE_W2 0.6900	W2	1	26.46	126
70739	CHEYRGW_W1 0.6900	W1	1	26.04	124
70742	CHEYRGW_W2 0.6900	W2	1	26.46	126
70753	BRONCO_W1 0.6900	W1	1	180	300
70758	CEP6_S1 0.6600	S1	1	162.8	250.47
70763	CEP5_S1 0.6600	S1	1	130	200
70777	COMAN_3 27.000	C3	1	780	804
70790	MIDWAY.PV 34.500	PV	1	40	100
70818	MTNBRZ_W1 34.500	W1	1	35.49	169
70823	CEDARCK_1A 34.500	W1	1	46.2	220
70824	CEDARCK_1B 34.500	W2	1	16.8	80
70825	CEDAR2_W1 0.6600	W1	1	26.25	125

70826	CEDAR2_W2 0.6900	W2	1	21.17	100.8
70827	CEDAR2_W3 0.6600	W3	1	5.25	25
70914	CEP7_S1 0.6300	S1	1	50.18	77.2
70931	GSANDHIL_PV 34.500	S1	1	12.35	19
70932	HOOPER_PV 34.500	S2	1	19.5	30
70933	COGENTRIX_PV34.500	S3	1	19.5	30
70934	COMAN_S1 0.4180	S1	1	81.25	125
70935	SUNPOWER 34.500	S1	1	33.8	52
70950	ST.VR_5 18.000	G5	1	149	162
70951	ST.VR_6 18.000	G6	1	148	162
71003	BAC_MSA GEN413.800	G1	1	40	40
71003	BAC_MSA GEN413.800	G2	1	40	40
71003	BAC_MSA GEN413.800	S1	1	24.8	24.8
71004	BAC_MSA GEN513.800	G1	1	40	40
71004	BAC_MSA GEN513.800	G2	1	40	40
71004	BAC_MSA GEN513.800	S1	1	24.8	24.8
71005	BAC_MSA GEN613.800	G1	1	40	40
71009	BUSCHRWTG1 0.7000	W1	1	4.44	28.8
71013	BUSCHRNCH_LO0.7000	W1	1	9.97	59.4
71016	PEAKVIEWLO 0.7000	W1	1	10	60
72703	CRSL_GEN 0.7000	W	1	136	148.4
72714	KC_GEN 0.7000	G1	1	46	51.2
72719	CT_GEN 0.6900	W	1	94	104.2
72739	NIYOL_GEN 0.6300	W1	1	180	200
73054	ELBERT-1 11.500	1	1	97	102.9
73129	MBPP-1 24.000	1	1	555.0248	605
73130	MBPP-2 24.000	1	1	550	605
73181	SIDNEYDC 230.00	1	1	50	200
73226	YELLO1-2 13.800	1	1	58	65.3
73226	YELLO1-2 13.800	2	1	62	65.3
73227	YELLO3-4 13.800	3	1	70	75.657
73227	YELLO3-4 13.800	4	1	60	65.3
73289	RCCT1 13.800	1	1	17	17
73291	RCCT2 13.800	2	1	17	17
73299	BIGTHOMP 4.2000	1	1	3	4.5
73302	BRLNGTN1 13.800	1	1	50	50.4
73303	BRLNGTN2 13.800	1	1	50	50.4
73306	ESTES1 6.9000	1	1	12	15.7
73307	ESTES2 6.9000	1	1	12	15.7
73308	ESTES3 6.9000	1	1	12	15.7

73316	GREENMT1 6.9000	1	1	11	14.444
73317	GREENMT2 6.9000	1	1	11	14.444
73319	MARYLKPP 6.9000	1	1	8	10.35
73324	POLEHILL 13.800	1	1	32	37.8
73328	WILLMFRK 2.4000	1	1	1.325	3
73332	ALCOVA1 6.9000	1	1	17	19.8
73333	BOYSEN1 4.2000	1	1	6	7.5
73333	BOYSEN1 4.2000	2	1	6	7.5
73334	BBILL1-2 6.9000	1	1	5	6.67
73334	BBILL1-2 6.9000	2	1	5	6.67
73339	HEART MT 2.4000	1	1	5	6.9
73341	NSS2 13.800	2	1	85	88
73347	SHOSHONE 6.9000	1	1	2	3.33
73349	FREMONT1 11.500	1	1	28	33.4
73350	FREMONT2 11.500	1	1	28	33.4
73351	GLENDO1 6.9000	1	1	16	19
73352	GLENDO2 6.9000	1	1	16	19
73353	GUERNSY1 2.4000	1	1	2	3.2
73356	KORTES1 6.9000	1	1	10	13.8
73357	KORTES2 6.9000	1	1	10	13.8
73358	KORTES3 6.9000	1	1	10	13.8
73363	SEMINOE1-2 6.9000	1	1	12	15
73363	SEMINOE1-2 6.9000	2	1	12	15
73438	ALCOVA2 6.9000	1	1	17	19.8
73439	BBILL3-4 6.9000	1	1	5	6.67
73441	SEMINOE3 6.9000	1	1	12	15
73444	GUERNSY2 2.4000	2	1	2	3.2
73448	FLATIRN1 13.800	2	1	45	47.8
73449	FLATIRN2 13.800	1	1	28	47.8
73449	FLATIRN2 13.800	3	1	7	8.5
73461	ELBERT-2 11.500	1	1	97	102.9
73462	SPIRTMTN 6.9000	1	1	4	5
73532	LINCOLN1 13.800	1	1	68	72.5
73533	LINCOLN2 13.800	1	1	68	67.5
73631	COHIWND_G1 0.7000	W	1	47	67.1
73635	COHIWND_G2 0.7000	W	1	16	23.1
74014	NSS CT1 13.800	1	1	40	37
74015	NSS CT2 13.800	1	1	40	37
74016	WYGEN 13.800	1	1	93	95
74017	WYGEN2 13.800	1	1	100	100

74018	WYGEN3 13.800	1	1	110	115
74029	LNG CT1 13.800	1	1	39.4	37
74042	CLR 1 0.6000	1	1	1.47	29.4
74043	SS_GEN1 0.6000	1	1	2.1	42
74061	CPGSTN 1 13.800	G1	1	40	37
74061	CPGSTN 1 13.800	G2	1	40	37
74062	CPGSTN 2 13.800	G1	1	40	37
74063	CPGSTN 3 13.800	G1	1	43	50
74063	CPGSTN 3 13.800	G2	1	43	50
74063	CPGSTN 3 13.800	S1	1	20	24.8
74203	CORWNDLO 0.6900	W1	1	2.6	52.92
76305	BARBERC1 13.800	1	1	7.2	7.2
76306	BARBERC2 13.800	1	1	7.2	7.2
76307	BARBERC3 13.800	1	1	7.2	7.2
76311	HARTZOG3 13.800	1	1	7.2	7.2
76313	TK DVAR1 0.5000	1	1	0	0.5
76314	TK DVAR2 0.5000	1	1	0	0.5
76351	RCDC W 230.00	1	1	-200	200
76404	DRYFORK 19.000	1	1	439.8	440
78011	RAWHIDE 24.000	C1	1	300	304
78012	RAWHIDEA 13.800	GA	1	65	70
78013	RAWHIDEB 13.800	GB	1	65	70
78014	RAWHIDEC 13.800	GC	1	65	70
78015	RAWHIDED 13.800	GD	1	65	70
78016	RAWHIDEF 18.000	GF	1	125	138
78022	RH_PV_GEN 0.6000	PV	1	20	32.4
78024	RPS_PV_GEN 0.4180	PV	1	5	32.4
78049	SPRCYN2_GEN 0.6000	W2	1	59	64.8
78053	RD_1_GEN 0.6900	W1	1	20.7	20.7
78054	RD_2_GEN 0.7000	W2	1	29	104.34
78515	FTRNG3CC 21.000	ST	1	207.7	208.2
78517	FTRNG1CC 18.000	G1	1	139.8	140.5
78518	FTRNG2CC 18.000	G2	1	140.6	141.3
78524	TESLA1 13.800	H1	1	24.2	28
78527	PIKE_PVPLANT0.6300	S1	1	91.9	175
78528	GYAK_PV1 0.6000	S1	1	18.4	35
78529	WC_PVPLANT 0.6300	S1	1	31.5	60
78537	TNGG_A 13.800	G1	1	27	27
78537	TNGG_A 13.800	G2	1	27	27
78537	TNGG_A 13.800	G3	1	27	27

78538	TNGG_B 13.800	G1	1	27	27
78538	TNGG_B 13.800	G2	1	27	27
78541	PIKE_BESS 0.6000	B1	1	25	25
78541	PIKE_BESS 0.6000	B2	1	25	25
78543	TNGG_FC 13.800	G1	1	27	27
78863	HORIZON 230.00	B1	1	108	117
79015	CRAIG.PV1 34.500	PV	1	240	400
79016	CRAIG.PV2 34.500	PV	1	240	400
79019	MORRO1-2 12.500	1	1	77	81
79019	MORRO1-2 12.500	2	1	77	81
79123	FONTNLLE 4.1600	1	1	8	11.111
79150	GLENC1-2 13.800	1	1	140	145
79150	GLENC1-2 13.800	2	1	140	145
79151	GLENC3-4 13.800	3	1	140	145
79151	GLENC3-4 13.800	4	1	140	145
79152	GLENC5-6 13.800	5	1	140	145
79152	GLENC5-6 13.800	6	1	140	145
79153	GLENC7-8 13.800	7	1	140	145
79153	GLENC7-8 13.800	8	1	140	145
79154	FLGORG1 11.500	1	1	50	56.1
79155	FLGORG2 11.500	1	1	50	56.1
79156	FLGORG3 11.500	1	1	50	56.1
79157	BMESA1-2 11.500	1	1	41	44
79157	BMESA1-2 11.500	2	1	41	44
79162	CRYSTAL 11.500	1	1	31	35
79164	TOWAOC 6.9000	1	1	10	12.1
79166	MOLINA-L 4.2000	1	1	3	4.9
79172	MOLINA-U 4.2000	1	1	7	8.6
79176	MCPHEE 2.4000	1	1	1	1.3
79251	QFATLAS1 13.800	1	1	15	34.7
79251	QFATLAS1 13.800	2	1	17.4	17.4
79252	QFATLAS2 13.800	3	1	17.4	17.4
79252	QFATLAS2 13.800	4	1	4.1	17.4
79612	BLUFFVW GEN113.800	1	1	40	45
79612	BLUFFVW GEN113.800	2	1	15	20
79642	NAV1 13.800	1	1	12	16
79642	NAV1 13.800	2	1	12	16
740039	TRK_CRK_PV 0.6000	1	1	200	217.8

Heavy Summer Case (Sensitivity with CPP Project Dispatch)

BUS	GENERATOR	UNIT	STATUS	PGen	PMax
70010	TBII_GEN 0.6900	W	1	70.2	78
70069	CABCRKA 13.800	HA	1	160	162
70070	CABCRKB 13.800	HB	1	160.38	162
70104	CHEROK2 15.500	SC	1	0	0
70106	CHEROK4 22.000	G4	1	360	335
70145	CHEROKEE5 18.000	G5	1	170	182
70146	CHEROKEE6 18.000	G6	1	170	182
70147	CHEROKEE7 18.000	ST	1	220	248
70188	FTLUP1-2 13.800	G1	1	40	50
70188	FTLUP1-2 13.800	G2	1	40	50
70310	PAWNEE 22.000	C1	1	460.8896	536
70314	MANCHEF1 16.000	G1	1	120	140
70315	MANCHEF2 16.000	G2	1	120	140
70487	JMSHAFR4 13.800	G4	1	34.8	34.8
70487	JMSHAFR4 13.800	G5	1	33	33
70490	JMSHAFR3 13.800	G3	1	36.1	36.1
70490	JMSHAFR3 13.800	ST	1	50	50
70493	JMSHAFR2 13.800	ST	1	26.2	50.7
70495	JMSHAFR1 13.800	G1	1	35.8	35.8
70495	JMSHAFR1 13.800	G2	1	35	35
70498	QF_BCP2T 13.800	G3	1	20	34.1
70498	QF_BCP2T 13.800	ST	1	20	36
70499	QF_B4-4T 13.800	G4	1	8	24
70500	QF_CPP1T 13.800	G1	1	13.5	24
70500	QF_CPP1T 13.800	G2	1	13.2	24
70501	QF_CPP3T 13.800	ST	1	15	27
70502	PIONEER_IR_S34.500	S1	1	52	80
70553	ARAP5&6 13.800	G5	1	38	39
70553	ARAP5&6 13.800	G6	1	38	39.5
70554	ARAP7 13.800	ST	1	43	47
70562	SPRUCE1 18.000	G1	1	130	145.1
70563	SPRUCE2 18.000	G2	1	130	140.5
70565	KNUTSON1 13.800	G1	1	67.5	72.5
70566	KNUTSON2 13.800	G2	1	40	72.5
70572	KIOWA_IR_S 34.500	S1	1	35.425	54.5
70577	FTNVL1&2 13.800	G1	1	40	40
70577	FTNVL1&2 13.800	G2	1	40	40
70578	FTNVL3&4 13.800	G3	1	40	40

70578	FTNVL3&4 13.800	G4	1	40	40
70579	FTNVL5&6 13.800	G5	1	40	40
70579	FTNVL5&6 13.800	G6	1	40	40
70580	PLNENDG1_1 13.800	G0	1	5	5.4
70580	PLNENDG1_1 13.800	G1	1	5	5.4
70580	PLNENDG1_1 13.800	G2	1	5	5.4
70580	PLNENDG1_1 13.800	G3	1	5	5.4
70580	PLNENDG1_1 13.800	G4	1	5	5.4
70580	PLNENDG1_1 13.800	G5	1	5	5.4
70580	PLNENDG1_1 13.800	G6	1	5	5.4
70580	PLNENDG1_1 13.800	G7	1	5	5.4
70580	PLNENDG1_1 13.800	G8	1	5	5.4
70580	PLNENDG1_1 13.800	G9	1	5	5.4
70585	PLNENDG2_1 13.800	G1	1	8	8.1
70585	PLNENDG2_1 13.800	G2	1	8	8.1
70585	PLNENDG2_1 13.800	G3	1	8	8.1
70585	PLNENDG2_1 13.800	G4	1	8	8.1
70585	PLNENDG2_1 13.800	G5	1	8	8.1
70585	PLNENDG2_1 13.800	G6	1	8	8.1
70585	PLNENDG2_1 13.800	G7	1	8	8.1
70586	PLNENDG2_2 13.800	G1	1	8	8.1
70586	PLNENDG2_2 13.800	G2	1	8	8.1
70586	PLNENDG2_2 13.800	G3	1	8	8.1
70586	PLNENDG2_2 13.800	G4	1	8	8.1
70586	PLNENDG2_2 13.800	G5	1	8	8.1
70586	PLNENDG2_2 13.800	G6	1	8	8.1
70586	PLNENDG2_2 13.800	G7	1	8	8.1
70587	PLNENDG1_2 13.800	G0	1	5	5.4
70587	PLNENDG1_2 13.800	G1	1	5	5.4
70587	PLNENDG1_2 13.800	G2	1	5	5.4
70587	PLNENDG1_2 13.800	G3	1	5	5.4
70587	PLNENDG1_2 13.800	G4	1	5	5.4
70587	PLNENDG1_2 13.800	G5	1	5	5.4
70587	PLNENDG1_2 13.800	G6	1	5	5.4
70587	PLNENDG1_2 13.800	G7	1	5	5.4
70587	PLNENDG1_2 13.800	G8	1	5	5.4
70587	PLNENDG1_2 13.800	G9	1	5	5.4
70593	SPNDLE1 18.000	G1	1	130	143.07
70594	SPNDLE2 18.000	G2	1	130	140.59
70602	GOOSECRK 34.500	1	1	750	750

70616	TITAN_S1 0.6300	S1	1	32.5	53.55
70629	RUSHCK_W1 34.500	W1	1	304	380
70631	RUSHCK_W2 34.500	W2	1	176	220
70635	LIMON1_W 34.500	W1	1	160.8	201
70636	LIMON2_W 34.500	W2	1	160.8	201
70637	LIMON3_W 34.500	W3	1	160.8	201
70646	CHEYNRD_W 34.500	W2	1	185.6	232
70647	CHEYNRD_E 34.500	W1	1	214.4	268
70665	GLDNWST_W1 0.6900	W1	1	26.06	124.1
70666	GLDNWST_W2 0.6900	W2	1	26.42	125
70670	CEDARPT_W1 0.6900	W1	1	26	124.2
70671	CEDARPT_W2 0.6900	W2	1	26.46	126
70701	CO_GRN_E 34.500	W1	1	73.2	81
70702	CO_GRN_W 34.500	W2	1	73.2	81
70703	TWNBUTTE 34.500	W1	1	68	75
70710	PTZLOGN1 34.500	W1	1	42.21	201
70712	PTZLOGN2 34.500	W2	1	25.2	120
70713	PTZLOGN3 34.500	W3	1	16.7	79.5
70714	PTZLOGN4 34.500	W4	1	36.8	175
70721	SPRNGCAN1_W10.5700	W1	1	59	64.8
70723	RDGCREST 34.500	W1	1	6.24	29.7
70753	BRONCO_W1 0.6900	W1	1	240	300
70758	CEP6_S1 0.6600	S1	1	162.8	250.47
70763	CEP5_S1 0.6600	S1	1	130	200
70790	MIDWAY.PV 34.500	PV	1	40	100
70818	MTNBRZ_W1 34.500	W1	1	35.49	169
70823	CEDARCK_1A 34.500	W1	1	46.2	220
70824	CEDARCK_1B 34.500	W2	1	16.8	80
70825	CEDAR2_W1 0.6600	W1	1	26.25	125
70826	CEDAR2_W2 0.6900	W2	1	21.17	100.8
70827	CEDAR2_W3 0.6600	W3	1	5.25	25
70914	CEP7_S1 0.6300	S1	1	50.18	77.2
70931	GSANDHIL_PV 34.500	S1	1	12.35	19
70932	HOOPER_PV 34.500	S2	1	19.5	30
70933	COGENTRIX_PV34.500	S3	1	19.5	30
70934	COMAN_S1 0.4180	S1	1	81.25	125
70935	SUNPOWER 34.500	S1	1	33.8	52
70953	MAY_VALLEY 34.500	1	1	750	750
71003	BAC_MSA GEN413.800	G1	1	40	40
71003	BAC_MSA GEN413.800	G2	1	40	40

71003	BAC_MSA GEN413.800	S1	1	24.8	24.8
71004	BAC_MSA GEN513.800	G1	1	40	40
71004	BAC_MSA GEN513.800	G2	1	40	40
71004	BAC_MSA GEN513.800	S1	1	24.8	24.8
71005	BAC_MSA GEN613.800	G1	1	40	40
71009	BUSCHRWTG1 0.7000	W1	1	4.44	28.8
71013	BUSCHRNCH_LO0.7000	W1	1	9.97	59.4
71016	PEAKVIEWLO 0.7000	W1	1	10	60
72703	CRSL_GEN 0.7000	W	1	151	148.4
72714	KC_GEN 0.7000	G1	1	51	51.2
72719	CT_GEN 0.6900	W	1	83	104.2
72739	NIYOL_GEN 0.6300	W1	1	160	200
73054	ELBERT-1 11.500	1	1	97	102.9
73129	MBPP-1 24.000	1	1	555.0248	605
73130	MBPP-2 24.000	1	1	550	605
73181	SIDNEYDC 230.00	1	1	50	200
73226	YELLO1-2 13.800	1	1	58	65.3
73226	YELLO1-2 13.800	2	1	62	65.3
73227	YELLO3-4 13.800	3	1	70	75.657
73227	YELLO3-4 13.800	4	1	60	65.3
73289	RCCT1 13.800	1	1	17	17
73291	RCCT2 13.800	2	1	17	17
73299	BIGTHOMP 4.2000	1	1	3	4.5
73302	BRLNGTN1 13.800	1	1	45	50.4
73303	BRLNGTN2 13.800	1	1	45	50.4
73306	ESTES1 6.9000	1	1	12	15.7
73307	ESTES2 6.9000	1	1	12	15.7
73308	ESTES3 6.9000	1	1	12	15.7
73316	GREENMT1 6.9000	1	1	11	14.444
73317	GREENMT2 6.9000	1	1	11	14.444
73319	MARYLKPP 6.9000	1	1	8	10.35
73324	POLEHILL 13.800	1	1	32	37.8
73328	WILLMFRK 2.4000	1	1	1.325	3
73332	ALCOVA1 6.9000	1	1	17	19.8
73333	BOYSEN1 4.2000	1	1	6	7.5
73333	BOYSEN1 4.2000	2	1	6	7.5
73334	BBILL1-2 6.9000	1	1	5	6.67
73334	BBILL1-2 6.9000	2	1	5	6.67
73339	HEART MT 2.4000	1	1	5	6.9
73341	NSS2 13.800	2	1	85	88

73347	SHOSHONE 6.9000	1	1	2	3.33
73349	FREMONT1 11.500	1	1	28	33.4
73350	FREMONT2 11.500	1	1	28	33.4
73351	GLENDO1 6.9000	1	1	16	19
73352	GLENDO2 6.9000	1	1	16	19
73353	GUERNSY1 2.4000	1	1	2	3.2
73356	KORTES1 6.9000	1	1	10	13.8
73357	KORTES2 6.9000	1	1	10	13.8
73358	KORTES3 6.9000	1	1	10	13.8
73363	SEMINOE1-2 6.9000	1	1	12	15
73363	SEMINOE1-2 6.9000	2	1	12	15
73438	ALCOVA2 6.9000	1	1	17	19.8
73439	BBILL3-4 6.9000	1	1	5	6.67
73441	SEMINOE3 6.9000	1	1	12	15
73444	GUERNSY2 2.4000	2	1	2	3.2
73448	FLATIRN1 13.800	2	1	45	47.8
73449	FLATIRN2 13.800	1	1	28	47.8
73449	FLATIRN2 13.800	3	1	7	8.5
73461	ELBERT-2 11.500	1	1	97	102.9
73462	SPIRTMTN 6.9000	1	1	4	5
73532	LINCOLN1 13.800	1	1	62	72.5
73533	LINCOLN2 13.800	1	1	62	67.5
73631	COHIWND_G1 0.7000	W	1	47	67.1
73635	COHIWND_G2 0.7000	W	1	16	23.1
74014	NSS CT1 13.800	1	1	40	37
74015	NSS CT2 13.800	1	1	40	37
74016	WYGEN 13.800	1	1	93	95
74017	WYGEN2 13.800	1	1	100	100
74018	WYGEN3 13.800	1	1	110	115
74029	LNG CT1 13.800	1	1	39.4	37
74042	CLR 1 0.6000	1	1	1.47	29.4
74043	SS_GEN1 0.6000	1	1	2.1	42
74061	CPGSTN 1 13.800	G1	1	40	37
74061	CPGSTN 1 13.800	G2	1	40	37
74062	CPGSTN 2 13.800	G1	1	40	37
74063	CPGSTN 3 13.800	G1	1	43	50
74063	CPGSTN 3 13.800	G2	1	43	50
74063	CPGSTN 3 13.800	S1	1	20	24.8
74203	CORWNDLO 0.6900	W1	1	2.6	52.92
76305	BARBERC1 13.800	1	1	7.2	7.2

76306	BARBERC2 13.800	1	1	7.2	7.2
76307	BARBERC3 13.800	1	1	7.2	7.2
76311	HARTZOG3 13.800	1	1	7.2	7.2
76313	TK DVAR1 0.5000	1	1	0	0.5
76314	TK DVAR2 0.5000	1	1	0	0.5
76351	RCDC W 230.00	1	1	-200	200
76404	DRYFORK 19.000	1	1	439.8	440
78011	RAWHIDE 24.000	C1	1	300	304
78012	RAWHIDEA 13.800	GA	1	65	70
78013	RAWHIDEB 13.800	GB	1	65	70
78014	RAWHIDEC 13.800	GC	1	65	70
78015	RAWHIDED 13.800	GD	1	65	70
78016	RAWHIDEF 18.000	GF	1	125	138
78022	RH_PV_GEN 0.6000	PV	1	20	32.4
78024	RPS_PV_GEN 0.4180	PV	1	5	32.4
78049	SPRCYN2_GEN 0.6000	W2	1	59	64.8
78053	RD_1_GEN 0.6900	W1	1	20.7	20.7
78054	RD_2_GEN 0.7000	W2	1	29	104.34
78515	FTRNG3CC 21.000	ST	1	207.7	208.2
78517	FTRNG1CC 18.000	G1	1	139.8	140.5
78518	FTRNG2CC 18.000	G2	1	140.6	141.3
78524	TESLA1 13.800	H1	1	24.2	28
78527	PIKE_PVPLANT0.6300	S1	1	91.9	175
78528	GYAK_PV1 0.6000	S1	1	18.4	35
78529	WC_PVPLANT 0.6300	S1	1	31.5	60
78537	TNGG_A 13.800	G1	1	27	27
78537	TNGG_A 13.800	G2	1	27	27
78537	TNGG_A 13.800	G3	1	27	27
78538	TNGG_B 13.800	G1	1	27	27
78538	TNGG_B 13.800	G2	1	27	27
78541	PIKE_BESS 0.6000	B1	1	25	25
78541	PIKE_BESS 0.6000	B2	1	25	25
78543	TNGG_FC 13.800	G1	1	27	27
78863	HORIZON 230.00	B1	1	108	117
79015	CRAIG.PV1 34.500	PV	1	260	400
79016	CRAIG.PV2 34.500	PV	1	260	400
79019	MORRO1-2 12.500	1	1	77	81
79019	MORRO1-2 12.500	2	1	77	81
79123	FONTNLLE 4.1600	1	1	8	11.111
79150	GLENC1-2 13.800	1	1	140	145

79150	GLENC1-2 13.800	2	1	140	145
79151	GLENC3-4 13.800	3	1	140	145
79151	GLENC3-4 13.800	4	1	140	145
79152	GLENC5-6 13.800	5	1	140	145
79152	GLENC5-6 13.800	6	1	140	145
79153	GLENC7-8 13.800	7	1	140	145
79153	GLENC7-8 13.800	8	1	140	145
79154	FLGORG1 11.500	1	1	50	56.1
79155	FLGORG2 11.500	1	1	50	56.1
79156	FLGORG3 11.500	1	1	50	56.1
79157	BMESA1-2 11.500	1	1	41	44
79157	BMESA1-2 11.500	2	1	41	44
79162	CRYSTAL 11.500	1	1	31	35
79164	TOWAOC 6.9000	1	1	10	12.1
79166	MOLINA-L 4.2000	1	1	3	4.9
79172	MOLINA-U 4.2000	1	1	7	8.6
79176	MCPHEE 2.4000	1	1	1	1.3
79251	QFATLAS1 13.800	1	1	15	34.7
79251	QFATLAS1 13.800	2	1	17.4	17.4
79252	QFATLAS2 13.800	3	1	17.4	17.4
79252	QFATLAS2 13.800	4	1	4.1	17.4
79612	BLUFFVW GEN113.800	1	1	40	45
79612	BLUFFVW GEN113.800	2	1	15	20
79642	NAV1 13.800	1	1	12	16
79642	NAV1 13.800	2	1	12	16
740039	TRK_CRK_PV 0.6000	1	1	200	217.8

APPENDIX C: Contingency List

P1.1 - Comanche.U3
P1.1 - Comanche.PV:230
P1.1 - Comanche.CEP2
P1.1 - Spanish Peaks
P1.1 - Lamar DC
P1.1 - Fountain Valley.U1.U2
P1.1 - Fountain Valley.U3.U4
P1.1 - Fountain Valley.U5.U6
P1.1 - Lincoln.1
P1.1 - Lincoln.2
P1.1 - Burlington.1
P1.1 - Burlington.2
P1.1 - Crossing Trails
P1.1 - Kit Carson
P1.1 - Carousel
P1.1 - Niyol
P1.1 - Peetz Logan.W1
P1.1 - Peetz Logan.W2
P1.1 - Peetz Logan.W3
P1.1 - Peetz Logan.W4
P1.1 - Pawnee
P1.1 - Manchief.U1
P1.1 - Manchief.U2
P1.1 - Limon.W1
P1.1 - Limon.W2
P1.1 - Limon.W3
P1.1 - Rush Creek.W1
P1.1 - Rush Creek.W2
P1.1 - Bronco
P1.1 - Cheyenne Ridge West.1
P1.1 - Cheyenne Ridge West.2
P1.1 - Cheyenne Ridge East.1
P1.1 - Cheyenne Ridge East.2
P1.1 - Titan.PV
P1.1 - Cedar Point
P1.2 - Lamar-Lamar:230
P1.2 - Lamar-Twin Buttes:230
P1.2 - Boone-Lamar:230

P1.2 - Lamar-Vilas:115
P1.2 - Lamar-Willow Creek:115
P1.2 - Willow Creek-La Junta:115
P1.2 - Boone-Midway (PSCo):230
P1.2 - Boone-Comanche:230
P1.2 - Comanche-Mirasol:230
P1.2 - Comanche-Midway (PSCo):230
P1.2 - Comanche-Daniels Park.1:345
P1.2 - Comanche-Tundra.2:345
P1.2 - Daniels Park-Tundra.2:345
P1.2 - Mirasol-Midway (PSCo):230
P1.2 - Midway (PSCo)-Fuller:230
P1.2 - Midway (PSCo)-Waterton:345
P1.2 - Midway (WAPA)-LincolnT:230
P1.2 - Midway (WAPA)-Canon West:230
P1.2 - Midway (WAPA)-R.D. Nixon:230
P1.2 - R.D. Nixon-FrontrangeG:230
P1.2 - R.D. Nixon-Williams Creek.1:230
P1.2 - R.D. Nixon-Williams Creek.2:230
P1.2 - R.D. Nixon-Keller South.1:230
P1.2 - Lincoln-Big Sandy:230
P1.2 - Big Sandy-Crossing Trails:230
P1.2 - Crossing Trails-Landsman Creek:230
P1.2 - Burlington-Wray:230
P1.2 - Wray-North Yuma:230
P1.2 - North Yuma-Story:230
P1.2 - North Yuma-Spring Canyon:230
P1.2 - Story-Pawnee:230
P1.2 - Story-Beaver Creek (PSCo):230
P1.2 - Story-Beaver Creek (TSGT):230
P1.2 - Story-Keota:345
P1.2 - Pawnee-Peetz Logan:230
P1.2 - Pawnee-Missile Site:230
P1.2 - Pawnee-Brickcenter:230
P1.2 - Pawnee-Ft. Lupton:230
P1.2 - Pawnee-Missile Site.1:345
P1.2 - Pawnee-Missile Site.2:345
P1.2 - Missile Site-Smoky Hill:345
P1.2 - Missile Site-Daniels Park:345
P1.2 - Missile Site-Limon:345

P1.2 - Limon-Limon:345
P1.2 - Limon-Limon:345
P1.2 - Missile Site-Pronghorn:345
P1.2 - Pronghorn-Shortgrass:345
P1.2 - Shortgrass-Cheyenne Ridge West:345
P1.2 - Cheyenne Ridge West-Bronco:345
P1.2 - Cheyenne Ridge West-Cheyenne Ridge East:345
P1.2 - Missile Site-Daniels Park:230
P1.2 - Daniels Park-Harvest Mile:345
P1.2 - Fuller-Daniels Park:230
P1.2 - Fuller-Fuller Wind:230
P1.2 - Fuller-Clarmont:230
P1.2 - Fuller-Briar:230
P1.2 - Briar-Cottonwood North:230
P1.2 - Clarmont-Stetson:230
P1.2 - Stetson-Cottonwood South:230
P1.2 - Cottonwood North-Cottonwood South:230
P1.2 - Harvest Mile-Smoky Hill:230
P1.2 - Cottonwood-Kettle.115
P1.2 - Cottonwood-Briar.115
P1.3 - Boone.T1
P1.3 - Comanche.T3
P1.3 - Comanche.T4
P1.3 - Midway (PSCo).T1
P1.3 - Story.T1
P1.3 - Story.T2
P1.3 - Pawnee.T3
P1.3 - Pawnee.T2
P1.3 - Missile Site.T1
P1.3 - Daniels Park.T3
P1.3 - Daniels Park.T3
P1.3 - Daniels Park.T5
P1.3 - Harvest Mile.T1
P1.3 - Smoky Hill.T4
P1.3 - Smoky Hill.T5
P2.2 - Midway 230 kV Tie
P1.2 - Comanche-Walsenburg:230
P1.2 - Boone-ComWal:230
P1.2 - Comanche-ComWal:230
P1.2 - Walsenburg-ComWal:230

P1.2 - Landsman Creek-Burlington:230
P1.2 - Story-Burlington Satellite:230
P1.2 - Landsman Creek-Burlington Satellite:230
P1.2 - Burlington-Burlington Satellite:230
P1.2 - Lamar-Burlington Satellite:230
P1.2 - Lamar-Burlington Satellite:345
P1.2 - Story-Burlington Satellite:345
P1.2 - Cheyenne Ridge East-Burlington Satellite:345
P1.2 - Cheyenne Ridge East-Story:345
P1.2 - Cheyenne Ridge East-Lamar:345
P1.2 - Tundra-Lamar:345
P1.2 - Story-Pawnee:345
P1.2 - Story-Henry Lake:230
P1.2 - Story-StoHenlk:230
P1.2 - Henry Lake-StoHenlk:230
P1.2 - Big Sandy-StoHenlk:230
P1.2 - Big Sandy-Story:230
P1.2 - Big Sandy-BooneE:230
P1.3 - Burlington Satellite:T1.345
P1.3 - Lamar:T1.345
P1.2 - Tundra-Comanche.345.1
P1.2 - Tundra-Daniels Park.345.1
P1.2 - Tundra-Harvest Mile.345.1
P1.2 - Tundra-May Valley.345.1
P1.2 - May Valley-Goose Creek.345.1
P1.2 - Goose Creek-Canal Crossing.345.1
P1.2 - Goose Creek-Cheyenne Ridge West.345.1
P1.2 - Canal Crossing-Pawnee.345.1
P1.2 - Ft. St. Vrain-Pawnee.345.1
P7 - Tundra-Comanche.345
P7 - Tundra-Daniels Park.345
P7 - Tundra-Harvest Mile.345
P7 - Tundra-May Valley.345
P7 - May Valley-Goose Creek.345
P7 - Goose Creek-Canal Crossing.345
P7 - Canal Crossing-Pawnee.345
P7 - Ft. St. Vrain-Pawnee.345

All transmission elements of an Alternative under study

APPENDIX D: Power Flow Results

Detailed power flow results are available separately, and are posted with the Final Report on the Responsible Energy Plan Task Force team page shown below.

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

Document Control

TRI-STATE
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Engineering Standards Bulletin

Preparation, Review, and Approval

Action	Name(s)	Title	Signature	Date
Prepared by:	C. Feinberg	Engineer, Transmission Planning		
Reviewed by:	M. Haag	Manager, Member and Regional System Planning		
Reviewed by:	R. Hubbard	Manager, Transmission Planning		
Approved by:	K. Carman	Vice President, Transmission Operations		
Approved by:	C. Pink	Vice President, Transmission Engineering		

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NAME(S)	DEPARTMENT	TITLE
K. Carman	Transmission Operations	Vice President, Transmission Operations
C. Pink	Transmission Engineering	Vice President, Transmission Engineering

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6.0	March 2012	ESB Rev 2012-3-06.pdf	Update facility ratings methodology, transformer efficiency, bibliography, and SOL methodology.
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8.0	July 2015	ESB_07_2015_final.pdf	Updated to make consistent with revised NERC standards and revised WECC criteria for system performance.
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TRI-STATE
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Engineering Standards Bulletin
Criteria for System Planning and Service Standards

Effective Date: June 2021
Areas Affected: Transmission System Planning
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Table of Contents

1.0 INTRODUCTION

This Engineering Standards Bulletin describes engineering methodologies and criteria to be used by Tri-State staff in transmission and member system planning, in accordance with Tri-State Board of Director's policies and Tri-State's Engineering Design Standards. Criteria outlined in this document should guide planners in making engineering assessments of various generation, transmission, and load-serving alternatives.

Implementation of these standards is intended to ensure safe and reliable operation of Tri-State's portion of the interconnected transmission system, and result in a more secure Bulk Electric System (BES). The end goal is that current and future customer demands be served reliably with adequate system voltage and frequency performance.

These standards apply to steady-state conditions, including power quality issues of harmonics and voltage unbalance, and transient conditions after a fault is cleared. Ratings of Tri-State owned and operated transmission circuits are dependent upon the rating of the most limiting element within the equipment that comprises the circuit. When and where the system does not adhere to these standards, several solution methods will be considered to resolve the deficiency. Depending on the specific technical and economic considerations, system solutions may include no action, establishing operating procedures, remedial action schemes, or justifying a new transmission project.

These standards apply at all times to the Tri-State system, with noted and documented exceptions for black-start and other system restoration periods. It is intended that such exceptions will be explicitly described and documented in operating procedures and supportive studies.

These criteria and standards are established in accordance with standards ordered by the Federal Energy Regulatory Commission (FERC); and developed by the North American Electric Reliability Corporation (NERC) and the Regional Reliability Organizations (RROs) with which Tri-State is associated, Western Electric Coordinating Council (WECC) and the Midway Reliability Organization (MRO). The majority of Tri-State's Member systems are in the WECC reliability jurisdiction. Some Member systems in Nebraska, eastern Wyoming and northeastern Colorado are either exclusively or additionally in the MRO reliability jurisdiction. Both WECC and the MRO are members of NERC. These criteria were developed in accordance with Tri-State connection and design standards, Large and Small Generator Interconnection Procedures, and Board of Director policies.

Other established electric utility industry standards and practices are used as guidelines to provide adequate reliability and service quality. See the Bibliography for more information. These standards are subject to change, as additional reliability practices develop and are adopted by FERC, NERC, WECC, MRO, and Tri-State.

2.0 DISCLOSURE

This bulletin includes facility rating methodologies which are in accordance with NERC Reliability Standard FAC-008-3. Refer to Tri-State's Power Flow, Dynamic, and Short Circuit Modeling Procedure for more detail on FAC-008-3 compliance.

If and when Tri-State identifies any Planning system operating limits (SOL), Tri-State shall follow the procedure for establishing and communicating SOLs as described in Tri-State's Transmission Assessment Standards Procedure in accordance with NERC Reliability Standard FAC-014-2.

To ensure reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs, Tri-State annually assesses and documents its portion of the Bulk Electric System in accordance with NERC Reliability Standard TPL-001-4. Refer to Tri-State's Transmission Assessment Standards Procedure for more detail on TPL-001-4 compliance. Table 1 from NERC Reliability Standard TPL-001-4 summarizes steady state and stability performance criteria for planning events can be found in Appendix A and is labeled as Table A3. Table A4 summarizes the steady state and stability performance requirements for extreme events per TPL-001-4.

3.0 RESPONSIBILITIES

The Power System Planning departments will apply these standards for the typical planning horizon, which is generally from one to ten years.

For those maintenance plans that impact the planning horizon, System Operations will notify System Planning to allow the appropriate planning studies to be completed. Potential mitigating options may include load shedding plans, installation of temporary reactive devices, or other mitigating measures as appropriate. New system facilities are not anticipated to be useful to mitigate system issues created by maintenance plans because of the temporary nature of maintenance outages.

The Vice Presidents of Transmission Engineering and Transmission Operations at Tri-State Generation and Transmission Association, Inc. are responsible for assuring these standards are implemented.

4.0 LOAD SHEDDING

Tri-State will perform required studies, and seek to identify additional system conditions for which frequency or voltage mitigation measures are necessary.

Tri-State's Under Frequency Load Shedding (UFLS) is coordinated, system-wide, and complies with the WECC and MRO's Under-Frequency Load Shedding Programs (see Appendix G: Bibliography for links). Because of Tri-State's service area, Tri-State participates in three distinct UFLS programs. The first is in the MRO jurisdiction and the other two programs are both in WECC's jurisdiction which are; the "Coordinated Plan – Table 1a", and the "Southern Island Load Tripping sub-area Coordinated Plan – Table 1c" which are both defined in WECC's UFLS coordinated plan documentation.

Unacceptable voltages during normal and contingency conditions will be assessed in accordance with this document. Multiple contingency voltage issues may be addressed via automatic under-voltage load shedding protection systems (UVLS) and/or training of system operators to switch VAR devices and/or shed key loads, as permitted by NERC Reliability Standard TPL-001-4. Established UVLS must be modeled in applicable study work, including annual assessments. Also, upon request by Transmission Operations, Planning will review UVLS applicability.

Refer to Tri-State's WECC/SPP-Assisted Studies Procedure for more detail on NERC Reliability Standard PRC-006-3 compliance

5.0 POWER FACTORS

Tri-State's power factor criteria is 0.95, leading or lagging, as measured at the point-of-interconnection or Delivery Point. Power factor shall be maintained within this band as averaged over a one hour interval. Tri-State plans the bulk transmission system assuming these power factor criteria are followed.

For loads that operate at a lower quality power factor during real-time operations, Tri-State will attempt to continue uninterrupted service. Tri-State Operations will take reasonable steps to maintain adequate system voltages, including switching nearby VAR devices or shedding load that is operating outside of acceptable power factor. If load is shed because its power factor is causing unacceptable system voltage, such load will be restored at the earliest opportunity, while maintaining adequate voltage levels.

Tri-State shall notify Members to correct low quality power factor at their respective interconnections which cause bulk transmission operational, contractual or compliance violations.

6.0 SYNCHRONIZING

There exist no relevant techniques for studying synchronizing operations. It is primarily a real-time operating consideration. Planning may recommend switching sequence for system restoration based on power flow modeling.

Synchroscopes are typically specified at key points in the transmission system to support black-start and restoration plans. Tri-State will participate in regional black-start and restoration studies and plan developments whenever such studies are required; and will recommend synch scopes locations to support the restoration plan.

7.0 BES PERFORMANCE

BES performance must meet the criteria listed below for acceptable system performance during study simulations.

7.1 STEADY-STATE CRITERIA

A system is in a steady-state condition when all quantities exhibit only negligible change over long periods of time and no transients are present. A transmission system is usually in a steady-state condition and, after a disturbance, will settle into a new steady-state condition typically between 10 seconds and one minute. Steady-State conditions are modeled using power flow modeling tools.

7.1.1 Operating Voltages

Acceptable operating voltages allow all loads, including machinery, lighting, and electronics, to operate as they were designed, without overloading and excessive loss-of-life. Tri-State's acceptable operating voltage criteria, which are in accordance with industry standard practices and standards, are summarized in Appendix A of this document.

7.1.1.1 Normal Conditions

Under normal system conditions (P0), all transmission facilities are in service with the exception of normally open transmission circuits. Acceptable steady-state transmission bus voltages will be between 0.95 and 1.05 per unit (p.u.) as shown in Table A1 of Appendix A.

7.1.1.2 Single Contingency Outage Conditions

Under single contingency outage (N-1) conditions (P1, P2), acceptable steady-state transmission bus voltages will be between 0.90 and 1.10 p.u.. All system devices designed to regulate operating voltages are allowed to adjust in simulations to meet this criterion.

7.1.1.3 Multiple Contingency Outage Conditions

Under multiple contingency outage (N-2 or more) conditions (P3, P4, P5, P6, P7), acceptable steady-state transmission bus voltages will be between 0.90 and 1.10 p.u.. All system devices designed to regulate operating voltages are allowed to adjust in simulations to meet this criterion.

Tri-State maintains a list of credible multiple contingencies. This credible contingency list will change as the system changes.

7.1.1.4 System Adjustments

Tri-State allows system (load tap changer, shunt capacitor/reactor, etc) adjustments to occur during single contingency outage simulations if automatic operation occurs.

7.1.1.5 Post-Contingency Voltage Deviation

Tri-State has set the post-contingency voltage deviation limit to be 8% across the entire system for P1 contingencies. No voltage deviation limit is applied for other contingencies.

7.1.1.6 Extended Outages

Known outages of generation facilities or transmission facilities of at least six months in duration will be modeled as part of planning studies.

7.1.1.7 VAR Capability

The VAR consumption of loads is addressed in Section 5.0. Generation facilities that interconnect with Tri-State's system are expected to have sufficient VAR capability to maintain 0.94 or lower power factor (pf), leading and lagging, as measured at the high-side of the generator substation. They are also expected to be in automatic voltage control so that the voltage schedule at the bus to which they are connected is met.

Reactive Power and voltage regulation requirements for generator interconnections are included in Appendix A of this document.

7.1.1.8 Voltage, Reactive Power and Power Factor Control

System simulations should assume that Tri-State will have the ability to directly control, or order prompt reactive power adjustments with all generation facilities that interconnect to the Tri-State system. Such control will be made a part of an interconnection agreement with any generation.

7.1.2 Loading

Transmission lines and transformers require acceptable loading levels so they do not exceed thermal or relay loadability limits. Exceeding the thermal limit of transmission line conductor can cause the conductor to sag excessively and fail to meet the minimum clearances required by applicable safety codes. Exceeding the thermal limit of transformers or other facilities can reduce the useful life of the equipment. Exceeding the relay loadability limits could cause undesired tripping of transmission facilities. Methods to establish transmission line static thermal ratings and transformer ratings are summarized in Appendix B. Conductor static thermal ratings, emergency ratings, and terminal equipment emergency ratings are summarized in Appendix C.

When performing system studies, flows on Transmission Transfer Paths must be monitored to assure that total path flows are below the ratings identified in the WECC Path Rating Catalog. Details for assessing these paths are included in Appendix H: Transmission Transfer Capability Assessment.

7.1.2.1 Normal Conditions

Under normal system conditions (P0), all transmission facilities are in service with the exception of normally open transmission circuits. Acceptable loading on any transmission line will not exceed 100% of its established continuous rating as shown in Table A1 of Appendix A. Transmission line conductors exceeding 80% of their ratings will be closely monitored during the study process for potential remediation. This criterion is in recognition of the high losses, high voltage drop, and possible steady-state stability problems associated with a line loaded above 80% of its static thermal rating.

Other facilities such as transformers and terminal equipment, including circuit breakers, current transformers, circuit switchers, disconnect switches, wave traps, line inductors, series capacitors, relays, and meters will be allowed to load to 100% of their continuous capabilities. These facilities do not create high losses, high voltage drops, or steady-state stability problems when heavily loaded, as do high voltage transmission lines.

7.1.2.2 Single or Multiple Contingency Outage Conditions

Under single contingency outage (N-1) conditions (P1, P2) and multiple contingency outage (N-2 or more) conditions (P3, P4, P5, P6, and P7), the maximum loading on any transmission line, transformer or terminal facility may not exceed 100% of its established continuous rating. If a short-term emergency rating has been established for a facility, it may be utilized in operating study simulations, but shall not be exceeded without remediation. Contingency definitions are documented in Appendix A.

Use of the emergency ratings must be limited to their proper application. Typically, established short-term ratings are 15-minute duration for transmission lines and 30-

minute duration for transformers. Short-term emergency ratings are established and documented in Appendices B and C.

7.1.3 RAS or Special Protection Schemes

A Remedial Action Schemes (RAS) as defined by NERC is an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and MVAR), or system configuration to maintain system stability, acceptable voltage levels, or acceptable power flow. A RAS does not include (a) underfrequency or undervoltage load shedding, (b) fault conditions that must be isolated, or (c) out-of-step relaying (not designed as an integral part of a RAS).

Established RAS must be modeled in applicable study work, including annual TPL assessments. Also, upon request by Transmission Operations, Planning will review RAS applicability. For reference, a summary of existing RAS is included in Appendix F: Remedial Action Schemes (RAS.

7.2 TRANSIENT STABILITY CRITERIA

Transient conditions exist during a transition from one steady-state condition to another. Transients may be caused by, for example, lightning strikes, faults, motor starting, switching shunt devices, and/or circuit breaker operation. Although the duration of a transient condition depends on system characteristics, it typically will last between ten seconds and one minute.

To mitigate any unstable generator unit operation, Tri-State will plan and design the system such that the clearing times of all primary and secondary protection systems are less than all critical clearing times for the system's most severe three-phase faults. It is expected that generating facilities have no consequential impact on the ability of the bulk electric system to meet transient stability performance criteria. Tri-State’s transient stability criteria are shown below, and are also listed in Appendix A.

- Following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 seconds of the initiating event for all P1 through P7 events, for each applicable BES bus serving load.
- Following fault clearing and voltage recovery above 80%, voltage at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds, for all P1 through P7 events.

- For Contingencies without a fault (P2.1 category event), voltage dips at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds.
- All oscillations that do not show positive damping within 30 seconds after the start of the studied event shall be deemed unstable.

7.3 SYSTEM INSTABILITY CRITERIA

7.3.1 Cascading

Cascading is uncontrolled successive loss of system elements triggered by an incident (or condition) at any location resulting in the interruption of widespread electric service that cannot be restrained from sequentially spreading beyond a predetermined area by studies. A potential consequence of cascading is uncontrolled separation or islanding. It is Tri-State's intent to operate the system such that cascading or uncontrolled separation/islanding does not occur - in all but the most catastrophic outage situations.

Cascading outages might conceivably result from the following initial conditions:

- Outages of major transfer path elements with high actual flows.
- Uncontrolled clearing of overloaded lines, causing overloads of other system elements.
- Failure or incorrect readings of line flow metering that "hide" overloads.
- Failure of load shedding relay schemes.

Modeling cascading outages requires knowledge of protective relay settings (relay loadability), load shedding schemes, and switching operations. The following describes the steady state criteria and methodology used to identify cascading or uncontrolled islanding:

Analysis is limited to three successive iterations. Operation of RAS that are not associated with the transmission station or substation being evaluated are permitted. After each iteration, facilities meeting the following criteria are removed from service and the case is re-solved.

1. Facilities loaded to 125% or greater of the seasonal short term emergency rating; this assumes automatic switching of devices if known to occur within one second of triggering system condition.

2. Generators with terminal voltages below 0.90 per unit (or applicable protection settings); since the voltage is below the normal rating for generators, tripping may be due to loss of auxiliary loads or plant operator action to protect the machine.

The process is repeated up to two additional times beyond the initial solution until either the case fails to converge, which indicates the potential for system collapse, or until no violations of the above two criteria are found, which indicates that the system has reached a stable operating point meaning cascading has not occurred in power flow. If after three iterations, the power flow converges but still has Transmission Facilities loaded to 125% or greater of the seasonal short term emergency rating or has generators with terminal voltages below 0.90 per unit (or applicable protection setting), then cascading is deemed to occur.

Extreme contingencies identified in Table A4, Appendix A of this document, that are expected to produce more severe system impact will be studied to determine potential cascading. If cascading is found to be caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event will be conducted.

Transient stability criteria to identify the potential for cascading or uncontrolled islanding are as follows:

- When transient stability voltage at any applicable BES bus fails to recover to 80% of the pre-contingency voltage within 20 seconds of the initiating event for all P1 through P7 events. Transient stability voltage recovery time is extended to 30 second for extreme events.
- All oscillations shall show positive damping within 30 seconds. Positive damping can be demonstrated by showing that the amplitude of power angle or voltage magnitude oscillations after 30 seconds is less than the initial post-contingency amplitude.

7.3.2 Voltage Instability/Collapse

Voltage instability, or voltage collapse, usually is a concern in regions that import a large amount of power. Often the operating voltage criteria are sufficient to mitigate voltage collapse concerns. However, receiving regions with sufficient shunt VAR support can approach voltage collapse even though the system operating voltages in the receiving region are acceptable. These voltage collapse criteria are intended to mitigate the voltage collapse risks of such systems by establishing a margin from the point of collapse of that system. The point of collapse can be measured in MW of load within the receiving region or MW flow across an interface. The point of collapse can also be expressed in terms of reactive power margin in MVAR. These voltage collapse criteria will be assessed though a voltage stability study, utilizing a P-V or Q-V analysis.

P-V and Q-V analysis will be performed in accordance with the WECC report titled, "Guide to WECC/NERC Planning Standards I.D: Voltage Support and Reactive Power", dated March 2006.

The following criteria will be used when identifying voltage stability:

- For transfer paths, all P0-P1 events shall demonstrate a positive reactive power margin at a minimum of 105 percent of transfer path flow.
- For transfer paths, all P2-P7 events shall demonstrate a positive reactive power margin at a minimum of 102.5 percent of transfer path flow.
- For load areas, all P0-P1 events shall demonstrate a positive reactive power margin at a minimum of 105 percent of forecasted peak load.
- For load areas, all P2-P7 events shall demonstrate a positive reactive power margin at a minimum of 102.5 percent of forecasted peak load.

8.0 POWER QUALITY

Power quality impacts are not typically identifiable in power flow or dynamics studies. The cause of poor power quality must be identified before mitigation measures can be implemented. Therefore, inadequate power quality will be identified through real-time operations, and studied with appropriate fault, harmonics or transients tools to identify mitigation options. Power quality at low side of the Delivery point will be evaluated to determine if the interconnected distribution system meets system operation criteria for harmonics and power factor. Identified distribution power quality issues that do not meet system operation criteria should be corrected on the distribution system or the low side of the Delivery point.

Poor power quality is typically an indication of the harmonic content in the system voltage and current, off-nominal voltages, or the degree to which the system is unbalanced between the phases. Poor power quality is not caused by power system disturbances or faults. Instead, it is usually caused by neighboring load, inverter systems and/or power electronics devices with improper levels of harmonic filtering equipment, or a misoperating device.

8.1 VOLTAGE FLUCTUATION AND FLICKER

Voltage fluctuations and flicker on power systems can cause noticeable changes in lighting, which can be significantly disruptive to customers. These disruptions are typically caused by large motor starts, or step-changes in voltage associated with switched devices such as shunt capacitor banks or reactors. Newer power electronics based devices and distributed energy resources can also be a source of flicker. Excessive flicker can trip sensitive electronic equipment and cause general customer irritation.

Although this criterion is directed at motor starting, it will be used as an indication of acceptable switching operations at Tri-State facilities. Unacceptable switching transients will be investigated on a case-by-case basis, as necessary.

The allowable voltage fluctuation and flicker criteria are summarized in Appendix E.

8.2 HARMONICS

The allowable harmonic voltage content at a Tri-State bus caused by a harmonic current producing load on the Tri-State or a Member system is described in IEEE 519-2014 “IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems”.

8.3 VOLTAGE UNBALANCE

The acceptable amount of voltage unbalance will be in accordance with ANSI C84.1. The goal is to limit the maximum steady-state voltage unbalance to 3 percent. Voltage unbalance will be measured at the customer’s service entrance with all loads disconnected.

The customer’s load may affect voltage measurements because of 3-phase load and power factor unbalance. Since it is not always practical to require the customer to disconnect all load, Tri-State may take measurements by measuring individual phase loads and power factors and calculating their effect on measurements taken without disconnecting the load.

When a customer’s three-phase service voltage is found to have an unbalance greater than 3 percent, Tri-State will act to reduce the unbalance and bring it within these limits within a reasonable length of time.

Percent Voltage Unbalance will be calculated as follows:

$$Percent\ Voltage\ Unbalance = 100\ X\ \frac{Maximum\ \ Voltage\ Deviation\ from\ Average\ Voltage}{Average\ Voltage}$$

8.3.1 Line Transpositions

To reduce voltage unbalance on the BES, Tri-State has adopted the following criteria when determining if transmission lines should be transposed:

- 115kV Transmission lines
    - Radial transmission lines are recommended to be transposed if longer than 85 miles in length.
    - Non-radial transmission lines longer than 85 mile in length will be analyzed by System Planning on a case-by-case basis to determine if line transpositions are recommended.

- 230kV Transmission lines
    - Radial transmission lines are recommended to be transposed if longer than 90 miles in length.
    - Non-radial transmission lines longer than 90 mile in length will be analyzed by System Planning on a case-by-case basis to determine if line transpositions are recommended.

- 345kV Transmission lines
    - Radial transmission lines
        - If typical loading is expected to be less than 597MVA, lines are recommended to be transposed if longer than 110 miles in length.
        - If typical loading is expected to be more than 597MVA, lines are recommended to be transposed if longer than 65 miles in length.
    - Non-Radial transmission lines
        - If typical loading is expected to be less than 597MVA, lines longer than 110 mile in length will be analyzed by System Planning on a case-by-case basis to determine if line transpositions are recommended.
        - If typical loading is expected to be more than 597MVA, lines longer than 110 mile in length will be analyzed by System Planning on a case-by-case basis to determine if line transpositions are recommended.

9.0 TRANSFORMER EFFICIENCY

Transformer efficiency is a fundamental parameter for purchasing and evaluating power transformers. The following methodology follows the format of transformer efficiency standards issued by the US Department of Energy in 10 CFR Part 431, Energy Conservation Program for Commercial Equipment: Distribution Transformers Energy Conservation Standards dated October 12, 2007.

9.1 DETERMINATION

Transformer efficiency is to be determined at the base rating by the following formula:

$$\text{Xfmr Eff.} = \frac{\text{Base Rating MVA} \quad * 100}{\text{Base Rating MVA} + \text{NLL} + \text{LL}}$$

where Xfmr Eff = transformer efficiency expressed as a percentage
NLL = no load losses
LL = load losses

9.2 MINIMUM TRANSFORMER EFFICIENCY

The minimum transformer efficiency for new HV and EHV transformers are indicated in Table 1 below. The appropriate efficiency should be used in specifying the purchase of a new transformer. Actual transformer efficiency should be verified by test data. These minimum efficiencies do not apply to existing units in the Tri-State transformer fleet.

Table 1 efficiency values are at 50 percent of nameplate rated load, using base MVA. MVA ratings in Table 1 are for a Delta-Wye, Wye-Wye, or auto-transformers with voltage ratio (HV/LV) of greater than 3.

Procedure to determine efficiency requirements for an auto-transformer with voltage ratio of less than or equal to 3 is as follows:

1. Co-ratio = 1-(LV/HV)

2. MVA rating used from chart = (Base MVA rating)/co-ratio

Example:

115kV-69kV, 30/40/50 MVA autotransformer

Co-ratio = 1 - (69kV/115kV) = 0.4

MVA rating used from chart = 30MVA/0.4 = 75 MVA, therefore an efficiency rating of 99.74% is required.

Table 1 Minimum Transformer Efficiency

SINGLE-PHASE		THREE-PHASE	
MVA	Efficiency %	MVA	Efficiency %
1	99.53	3	99.53
1.667	99.55	5	99.55
2.5	99.56	7.5	99.56
3.33	99.58	10	99.58
4	99.60	12	99.60
5	99.62	15	99.62
6.66	99.64	20	99.64
8.33	99.66	25	99.66
10	99.68	30	99.68
15	99.70	45	99.70
20	99.72	60	99.72
25	99.74	75	99.74
33.3	99.76	100	99.76
50	99.77	150	99.77
66.67	99.78	200	99.78
83.3	99.80	250	99.80
100	99.82	300	99.82
133.3	99.83	400	99.83
150	99.84	450	99.84
166.7	99.84	500	99.84
200	99.86	600	99.86
250	99.90	750	99.90

Notes:

- Transformers with MVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the MVA and efficiency values immediately above and below that MVA rating.
- Since "power class" transformer can have additional ratings such as 55/65° C Rise or Forced Cooled ratings, all efficiency values to be at:
  - No Load Losses @ 100% rated voltage, corrected to a temperature of 20°C
  - Load Losses @ the lowest nameplate rated MVA, corrected to a temperature of 75°C
  - Determined according to the DOE Test-Procedure. 10 CFR Part 431, Subpart K, Appendix A.

9.3 TRANSFORMER LOSS EVALUATION

New transformer purchases should be evaluated using estimated losses provided by the manufacturer, applying appropriate loss values. The estimated losses should be verified with acceptance test data for each transformer delivered to Tri-State. Any losses higher than represented in the manufacturers estimate should be addressed according to the purchase contract requirements. Loss evaluation values are as follows:

No Load Losses = $ 2,976 per kW

Load Losses = $ 1,819 per kW

Aux Losses = $ 1,939 per kW
(For banks with 55C rating up to 45 MVA)

Aux Losses = $ 6759 per kW
(For banks with 55C rating up to 450 MVA)

Note: These loss evaluation values are subject to change and the values should be verified prior to transformer purchase specifications.

10.0 DATA PREPARATION PROCEDURE FOR STEADY-STATE, SHORT CIRCUIT, AND DYNAMICS MODELING AND SIMULATION DATA

Refer to Tri-State's Power Flow, Dynamic, and Short Circuit Modeling Procedure for more detail on MOD-25-2, MOD-026-1, MOD-027-1, and MOD-032-1 compliance.

APPENDIX A: PLANNING CRITERIA

Table A1

Tri-State Equipment Loading Criteria		
System Condition	**Maximum Loading[1] (Percent of Continuous Rating)**	
	Transmission Lines	**Other Facilities**
Normal (P0 event)	80/100	100
Contingency (P1-P7 event)	100	100

Table A2

Tri-State Voltage Criteria		
System Condition	**Operating Voltages[2]**	**Delta-V**
Normal (P0 event)	0.95 - 1.05 p.u.	
Contingency (P1 event)	0.90 - 1.10 p.u.	8%
Contingency (P2-P7 event)	0.90 - 1.10 p.u.	-

[1] The continuous rating is synonymous with the normal/static thermal rating. Facilities exceeding 80% criteria will be flagged for close scrutiny. By no means, shall the 100% rating be exceeded without regard in planning studies.
[2] Exceptions may be granted for high side buses of Load-Tap-Changing (LTC) transformers that violate this criterion, if the corresponding low side busses are well within the criterion.

Table A3

Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event[1]	Fault Type[2]	BES Level[3]	Interruption of Firm Transmission Service Allowed[4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault[7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault (non-Bus-tie Breaker)[8]	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker[10] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments[9]. 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure[11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Basic WECC Dynamic Criteria:

Tri-State's dynamic reactive power and voltage control / regulation criteria are in accordance with the NERC/WECC dynamic performance criteria and are as follows:

- Following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 seconds of the initiating event for all P1 through P7 events, for each applicable BES bus serving load.
- Following fault clearing and voltage recovery above 80%, voltage at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds, for all P1 through P7 events
- For Contingencies without a fault (P2.1 category event), voltage dips at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds.
- All oscillations that do not show positive damping within 30 seconds after the start of the studied event shall be deemed unstable.

Table A4

<table>
<tr><th colspan="2">Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">Steady State & Stability
For all extreme events evaluated:
a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
b. Simulate Normal Clearing unless otherwise specified.</td></tr>
<tr><td>Steady State
1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.

2. Local area events affecting the Transmission System such as:
a. Loss of a tower line with three or more circuits.[11]
b. Loss of all Transmission lines on a common Right-of Way[11].
c. Loss of a switching station or substation (loss of one voltage level plus transformers).
d. Loss of all generating units at a generating station.
e. Loss of a large Load or major Load center.

3. Wide area events affecting the Transmission System based on System topology such as:
a. Loss of two generating stations resulting from conditions such as:
i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
ii. Loss of the use of a large body of water as the cooling source for generation.
iii. Wildfires.
iv. Severe weather, e.g., hurricanes, tornadoes, etc.
v. A successful cyber attack.
vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly</td>
<td>Stability
1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.

2. Local or wide area events affecting the Transmission System such as:
a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault.
f. f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances</td></tr>
</table>

designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	

Table A5

Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. 2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. 3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. 4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. 5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.

7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.

8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.

9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non- Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.

10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.

11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non- Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

APPENDIX B: EQUIPMENT RATING METHODOLOGIES

Major BES Equipment Rating Methodologies

Power system facilities are the circuitry between the nodes of the network. The most common facilities are transmission lines, transformers, generators and VAR devices. **Tri-State's facility ratings equal the most limiting applicable Equipment Rating of the individual equipment associated with that Facility and will consider manufacturer ratings, design criteria, ambient conditions, operating limitations, and/or other applicable assumptions when calculated**. Short-term system operation limits (SOLs) shall be determined, if necessary, on a case-by-case basis by Transmission Operations based on seasonal conditions.

Generators

Tri-State's Transmission function utilizes the generator ratings provided by the merchant function. Nameplate capability is utilized unless superseded by actual test data. Performance tests are performed periodically to confirm VAR capability and dynamic characteristics.

Overhead Conductors

Tri-State's conductor rating methodology is based on a detailed statistical analysis of historical mean hourly weather data across the Tri-State service territory. Tri-State uses Electric Power Research Institute (EPRI) developed software, StatRat, to perform the statistical analysis.

The conductor ratings apply to the entire line, including the last span of the line entering the substation. Static thermal ratings of conductors at standard design temperatures and overload percentages utilized by Tri-State are summarized in Appendix C: Equipment Thermal and Emergency Ratings. Static thermal ratings of transmission lines which are designed to a non-standard temperature will be calculated on a case-by-case basis using the methods described in IEEE 738-1993 "IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors".

The regional conductor rating methodology utilizes five fundamental weather regions in establishing conductor ratings. The regions are described as follows:

- **Region 1** – North and Central Wyoming
- **Region 2** – South Eastern Wyoming; Western Nebraska; North Eastern Colorado
- **Region 3 –** Western Colorado; North Western New Mexico
- **Region 4** – Eastern Colorado; North Eastern New Mexico
- **Region 5** – Central and Southern New Mexico

A map detailing the regional boundaries across Tri-State's system can be found in Tri-State's Geographic Information System (GIS). Any transmission line routed through two or more regions will be rated using the lowest conductor rating listed for its associated regions.

Tri-State's conductor ratings are calculated using Typical Meteorological Year (TMY3) data. The TMY3 data sets were produced by National Renewable Energy Lab's Electric and Systems Center. TMY3 data for the following weather stations were averaged together in determining the regional ratings:

- **Region 1** – Casper, WY; Cody, WY; Lander, WY; Riverton, WY
- **Region 2** – Akron, CO; Denver International Airport, CO; Fort Collins, CO; Golden, CO; Greeley, CO; Scottsbluff, NE; Cheyenne, WY; Laramie, WY, Rawlins, WY
- **Region 3** – Alamosa, CO; Cortez, CO; Durango, CO; Grand Junction, CO; Hayden, CO; Leadville, CO; Montrose, CO; Farmington, NM; Taos, NM
- **Region 4** – Colorado Springs, CO; La Junta, CO; Lamar, CO; Limon, CO; Pueblo, CO; Trinidad, CO; Goodland, KS; Clayton, NM
- **Region 5** – Albuquerque, NM; Deming, NM; Holloman Air Force Base, NM; Las Cruces, NM; Las Vegas, NM; Santa Fe, NM; Sierra Blanca, NM; Truth or Consequences, NM; Tucumcari, NM, El Paso, TX

The following assumptions[3] were used in calculation of conductor ratings:

Table B1

Emissivity	0.7
Absorption	0.9
Wind Angle	45°
Wind Speed (ft/s)	**Day time**: 4 ft/s unless TMY3 weather data is larger **Night Time**: 2 ft/s unless TMY3 weather data is larger

For each conductor type in service at Tri-State, an hourly capacity is determined for each of the hourly weather observations following IEEE 738-1993 "IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors", establishing a complete picture of the weather and its effects on conductor ratings. This extensive rating data for a given conductor is then sorted from lowest to highest, and the static thermal rating for that conductor is set at the first percentile based on the sorted data. This is also the point at which the local weather can be expected to support the established static thermal conductor rating 99% of the time. The first percentile rating is used as a year around static thermal rating for each conductor.

To calculate a year around 15-minute and 30-minute emergency ratings, a normalized overload percentage is calculated using Southwire's SWRate software v3.02 assuming the following:

Table B2

Emissivity	0.7
Absorption	0.9

[3] Assumptions based on research documented in the Tri-State report, "Statistically Determined Static Thermal Ratings of Overhead High Voltage Transmission Lines in the Rocky Mountain Region" dated April 1998, and the Electric Power Research Institute (EPRI) report, "Determination of Static Conductor Thermal Rating using Statistic Analysis in the Rocky Mountain and Desert Southwest Area" dated June 2007.

Wind Speed	4 ft/sec
Wind Angle	45°
Ambient Temperature	40°C
Frequency	60 Hz
Altitude	5000 ft
N. Latitude	38 degrees
Line Azimuth	0 degrees
Local Time	12 – noon
Solar Day	July 15th
Max Conductor Temperature	100°C
Pre-disturbance Loading	80%

The normalized overload percentage for 15 minutes and 30 minutes is applied to the first percentile rating to determine the year around emergency ratings. Tri-State does not normally establish seasonal emergency ratings. If they are deemed necessary, however, they will be determined on a case by case basis.

Transformer Ratings

Transformer ratings are determined by the nameplate ratings based on maximum cooling. If available, the rating with a 65°C oil temperature rise will be used, otherwise, the 55°C oil temperature rise will be used. Summer ambient temperatures will be presumed, unless a winter rating is necessary. The Rated Operating Temperature for Power Transformers at Tri-State is 85ºC (55ºC Rise over a 30ºC Ambient) or 95 ºC for 65 ºC rated transformers which is limited by the coil insulation. The outdoor ambient temperature is a 24-hour average temperature as specified by IEEE C57.12.00 – 2015 "IEEE Standard for Standard General Requirements For Liquid-Immersed Distribution, Power, and Regulating Transformers". Thirty minute and four-hour short-term emergency ratings for large power transformers shall be determined using guidance found in ABB Electrical Transmission and Distribution Reference Book, Fifth Edition, Copyright 1997, Table 9 in Chapter 5,"Permissible Daily Short-Time Transformer Ratings Based on Normal Life Expectancy." A pre-emergency loading of 70% of maximum nameplate is used to conservatively account for various ages of equipment and variety of operating conditions on the Tri-State system. This reference recommends a thirty-minute short-term emergency rating of 146% of maximum nameplate rating, and a four-hour short-term emergency rating of 110% of the maximum nameplate rating. Tri-State chooses to take a more conservative approach and uses the following emergency limits:

- 30-minute short-term emergency rating – 125% of maximum nameplate rating
- 4 hour short-term emergency rating – 110% of maximum nameplate rating

Transformers that have compromised cooling systems or show accelerated aging using dissolved gas analysis shall be handled, if necessary, on a case-by-case basis.

Relay Protective Devices

There are two basic types of relay protective devices that can limit loading and the methodology for their ratings is slightly different.

Impedance type relay load limits are based on the value of the pickup of their most sensitive phase impedance element for a given load power factor. Typically, a load power factor angle of 30 degrees (0.87 pf) at .85 p.u. voltage will be assumed, as required in NERC Reliability Standard PRC-023-4. Special cases, however, may necessitate using a different loading criterion. In these cases, the loading criteria will be based on special studies. In non-radial systems, there will likely be a relay at each terminal of the line affecting relay loadability. In these cases, the most limiting relay element of the two will be used.

Phase overcurrent relay load limits will be based on the pickup value of their most limiting phase overcurrent element, independent of the load power factor.

Tri-State will also specify relays with a minimum 10-Ampere continuous capability, so that the relaying equipment can withstand the full capability of its associated current transformer, at a minimum. Emergency ratings for relay protective device settings will be identical to the normal ratings.

Circuit Breaker Ratings

Circuit Breakers will be rated according to the manufacturer's nameplate ampacity at the nominal applied voltage which defines guaranteed minimum capacities under Usual Service Conditions as specified in IEEE C37.04-2018 "IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers." This rating is a continuous 24-hour rating. Bushing-mounted current transformers that are supplied power circuit breakers will be rated according to the corresponding unit's nameplate in accordance with IEEE C57.13-2016 "IEEE Standard Requirements for Instrument Transformers" Section B.4 and B.5, respectively.

The ratings of the connectors will be assumed identical to the nameplate ratings of the devices to which they are fitted, and will not be separately calculated. Continuous current ratings for connectors used to terminate conductors to bushings and other conductors will be rated the same as the conductor per ANSI C119.4-2011, and will not be separately calculated. For facilities that terminate in a multiple breaker arrangement, such as in a ring bus, breaker-and-a-half, or double-breaker-double-bus configuration, the rating of the lowest rated circuit breaker associated with the circuit will be used. This will allow maintenance to occur on one of the breakers without re-rating the facility during maintenance.

Short-term emergency ratings shall be determined using the guidance provided by Table 5b. Assuming the 40°C ambient and pre-load of 100% of nameplate rated current, the emergency rating for 30-minute duration is 119% and for four-hour duration is 112%. Circuit Breakers that have bushings or internal CTs that are non-standard or have an observed tendency to run hotter than the device tank shall have emergency ratings determined on a case-by-case basis, using provisions in the above standards documents.

Current Transformer Ratings

Outdoor Current Transformer ratings will be determined by manufacturer provided information, such as the nameplate in accordance with IEEE C57.13-2016 "IEEE Standard Requirements for Instrument Transformers" Section 6.1, by the setting of the device, and by other technical documents as detailed below. Bushing-mounted current transformers that are supplied with power transformers and power circuit breakers will be rated, for both normal and short-time emergency ratings, according to the corresponding unit's nameplate and applicable standard in accordance with IEEE C57.13-2016 Section B.4 and B.5, respectively. Tri-State's outdoor current transformers follow the industry standard that includes nominal five-Ampere secondary windings. A thermal rating factor will be applied to determine if the current transformer is capable of more than 5.0 Amperes continuously in the secondary winding. The thermal rating factor is provided by the manufacturer on the nameplate per C57.13-2016 "IEEE Standard Requirements for Instrument Transformers" Section 6.8. If a thermal rating factor is not available due to incomplete manufacturer documentation provided by the manufacturer, a thermal rating factor may be developed based on a Westinghouse "Memorandum on Thermal Current Characteristics of Current Transformers used with Power Circuit Breakers and Power Transformers" dated June 26, 1969. Both of these values reflect to the primary winding of the current transformer, establishing a high side rating for the device.

Mathematically, a current transformer rating is determined as follows:

Primary Winding Rating = CT Primary Setting * CT Thermal Rating Factor (TRF)

where TRF is the product, not normally exceeding 2.0, of any manufacturer-provided thermal rating factor and the factor developed from the referenced Westinghouse memorandum. TRF may exceed 2.0 only in those cases where the manufacturer explicitly provides a TRF greater than 2.0.

For facilities that terminate in a multiple breaker arrangement, such as in a ring bus, breaker-and-a-half, or double-breaker-double-bus configuration, the rating of the lowest rated current transformer associated with the circuit will be used. This will allow maintenance to occur on one of the breakers without re-rating the facility during maintenance.

Short-term emergency ratings shall be determined using the guidance provided by Figure 20, "Overload Capability of Current Transformers" found in the ABB publication Instrument Transformers: Technical Information and Application Guide, Revision A, from December 2004. Assuming the 30°C average ambient and pre-load of 100% of nameplate rated current, the emergency rating for 30-minute duration is 170% and for four-hour duration is 119%. Outdoor Current Transformers that are non-standard or have an observed tendency to run hotter than normal shall have emergency ratings determined on a case-by-case basis, using provisions in the above standards documents and the judgment of substation maintenance personnel.

Disconnect Switches

Switches will be rated according to the manufacturer's nameplate ampacity at the nominal applied voltage which defines guaranteed minimum capacities under Usual Service Conditions as specified in IEEE C37.30.1-2011. Continuous current ratings for connectors used to terminate conductors to switches will be rated the same as the conductor per ANSI C119.4, and will not be separately calculated.

For facilities that terminate in a multiple breaker arrangement, such as in a ring bus, breaker-and-a-half, or double-breaker-double-bus configuration, the rating of the lowest rated disconnect switch associated with the circuit will be used. This will allow maintenance to occur on one of the breakers without re-rating the facility during maintenance.

Short-time emergency ratings shall be assigned to outdoor switches using provisions of IEEE C37.30.1-2011 "IEEE Loading Guide for AC High-Voltage Air Switches (in Excess of 1000 V)", Annex A, Figure 3. The short-time emergency rating shall be 122% of the continuous rating for both 30-minute and 4-hour ratings. For switches of non-standard design or construction and switches that exhibit anomalous thermographic patterns, short-term emergency ratings shall be determined on a case-by-case basis, using provisions in the above standards documents and the experience of substation maintenance personnel.

Wave Traps

Power line carrier wave trap (line trap) ratings are determined by the manufacturer's nameplate rating of the device consistent with ANSI C93.3-2017, "Requirements for Power-Line Carrier Line Traps".

Emergency Ratings shall be based on the altitude correction factor in Section 4.2.2.1, Table 2 and in Table A1 of the above standard based on the 40°C ambient consistent with the transmission line emergency ratings. The 30-minute emergency rating of Wave Traps is 129% and the four-hour emergency rating is equal to the normal rating, due to thermal considerations. Wave Traps determined to have limited capability due to aging or damage shall have emergency ratings determined on a case-by-case basis, using provisions in the above standard document.

Metering Equipment

Metering equipment will be specified to have a minimum 10-Ampere continuous capability, so that the metering equipment can withstand the full capability of its associated current transformer, at a minimum. Normal and emergency ratings for Metering Equipment are identical.

Monitoring equipment, such as WATT/VAR transducers, panel meters, and RTU interface circuitry are used for monitoring by system operators, among others. These subsystems may have limitations or saturation points that cause a ceiling or floor on observed parameters if exceeded, even though the hardware limitations are not exceeded. As operation of the system in excess of these values would render observed SCADA values incorrect, they should not be exceeded and must be taken into account when metering equipment ratings are determined.

Other Secondary Terminal Equipment

In general, other terminal equipment not specifically identified in this document will be rated via a nameplate rating. Further, where applicable, such equipment will have minimum 10-Ampere continuous capability. Normal and emergency ratings will be identical.

Series Capacitors and Reactors

Tri-State does not currently have any series capacitor or reactor installations. However, the series capacitor or reactor ratings, if installed, will be based on the nameplate capability as determined by the manufacturer, and the normal and emergency ratings will be determined consistent with IEEE 824-2004 “IEEE Standard for Series Capacitor Banks in Power Systems”, and IEEE C57.16-2011 “IEEE Standard Requirements, Terminology, and Test Code for Dry-Type Air-Core Series-Connected Reactors”, Section 5. Normal and emergency ratings will be identical. If needed, short-term emergency ratings shall be determined, if necessary, on a case-by-case basis, using provisions in the above standards documents.

Shunt Reactive Devices

Shunt reactive device ratings will be established via nameplate ratings established by the manufacturer as described in IEEE C57.21-2008 “IEEE Standard Requirements, Terminology, and Test Code for Shunt Reactors Rated over 500 kVA”, Section 5; and IEEE Std 18-2012 “IEEE Standard for Shunt Power Capacitors”, Sections 4 and 5. Normal and emergency ratings will be identical. If needed, Short-term emergency ratings shall be determined, if necessary, on a case-by-case basis, using provisions in the above standards documents.

This section also applies to the shunt reactive components on FACTS and other advanced power electronics.

DC Ties

With the exception of Stegall, Tri-State currently has no DC ties. This section also applies to series reactive components as part of FACTS and other advanced power electronics devices. DC Tie ratings are determined by the manufacturer. Normal and emergency ratings are identical.

Underground Cables

Underground cables will be rated according to the manufacturer’s design, in combination with the ambient in-situ conditions (soil resistivity, nearby UG parallel cables, ambient temperature, etc.). Short-term emergency ratings shall be determined on a case-by-case basis.

Substation Jumpers

Jumpers are rated using the same methodology as overhead conductors for normal and emergency ratings. A static thermal temperature of 100 degrees C shall be assumed for all strandings, tempers, and cores.

For facilities that terminate in a multiple breaker arrangement, such as in a ring bus, breaker-and-a-half, or double-breaker-double-bus configuration, the rating of the smallest series-connected jumper associated with the circuit will be used. Ratings of jumpers connected to shunt equipment (Potential Transformers, etc.) shall be applied to the shunt connected equipment only, not the line.

Substation Bus

Ratings of substation buswork shall be based on IEEE 605-2008, "IEEE Guide for Design of Substation Rigid-Bus Structures" in Section 5. Unless directed otherwise, on a case-by-case basis, by Tri-State's substation engineering group, assumptions shall include Emissivity = 0.5, with Sun, and temperature rise above 40 degrees C ambient; and ampacities found in Annex B of the standard based on a maximum bus temperature of 70°C.

Ratings of substation strain bus shall follow the same criteria as Substation Jumpers, described above. A maximum static thermal temperature of 100°C shall be assumed.

For facilities that terminate in a multiple breaker arrangement, such as in a ring bus, breaker-and-a-half, or double-breaker-double-bus configuration, the rating of the smallest series-connected bus associated with the circuit will be used.

Short-term emergency ratings shall be determined, using the provisions of the above cited Annex B for the appropriate bus shape and a maximum conductor of 110°C for the 30-minute short time emergency and 100°C for the four-hour emergency rating. This rating shall be considered appropriate for both copper and aluminum bus conductors to avoid separate calculations. In the case of a bus that has non-standard size, thickness, shape, or mechanical support, the short-time emergency ratings shall be determined on a case-by-case basis. Rigid station bus that is mechanically fixed at both ends, without expansion joints shall also be evaluated on a case-by-case basis due to forces exerted on, and possible damage to, station equipment using provisions in the above standard document.

As an example, 4-inch Schedule 40 tubular aluminum (53% Conductivity) using the same ambient conditions as noted above would have a normal rating of 2015 Amps, a 30 Minute emergency rating of 3635 Amps (180% of normal rating), and a 4-hour rating of 3315 Amps (164% of normal rating). Because of the variety of shapes and metals used in station bus, it is difficult to support a system-wide short time emergency rating above 146% for 30 Minutes and 136% for 4 Hours. This is based on values for the smallest buses across multiple bus materials and shapes, and is the most limiting of the metals and shapes generally used in station bus construction.

Jointly Owned Equipment Rating Methodology

BES facilities where Tri-State shares equipment ownership with another entity will be rated and monitored the same as facilities solely owned by Tri-State, unless another entity with partial ownership states that they will rate the equipment on our behalf.

Facilities which include equipment not owned by Tri-State will be rated. Tri-State equipment for these jointly owned facilities will be rated and monitored as normal, and the most limiting element ratings will be provided to other entities through regular reports. Emergency ratings will be provided upon request. Limiting element ratings will be received from the other entities who own equipment for these facilities. Emergency ratings are assumed to be equal to normal ratings unless otherwise specified.

APPENDIX C: EQUIPMENT THERMAL AND EMERGENCY RATINGS

Table C1
Tri-State Overhead Conductor Static Thermal Ratings
(Amperes)

Conductor Type	Maximum Conductor Temperature (Celsius)	Region 1 (NC WY)	Region 2 (SE WY/NE CO/ W NE)	Region 3 (W CO/ NW NM)	Region 4 (E CO/ NE NM)	Region 5 (S NM)
Falcon 1590 (ACSR) 54/19 Stranding	50 75 100	1012 1571 1877	1000 1575 1878	972 1534 1828	932 1554 1862	824 1477 1800
Pheasant 1272 (ASCR) 54/19 Stranding	50 75 100	885 1362 1623	877 1366 1624	853 1331 1581	820 1348 1611	729 1281 1557
Bittern 1272 (ASCR) 45/7 Stranding	50 75 100	880 1358 1625	872 1362 1627	849 1327 1584	816 1344 1613	726 1278 1559
Cardinal 954 (ACSR) 54/7 Stranding	50 75 100	745 1134 1347	740 1137 1349	721 1108 1313	694 1122 1338	619 1066 1293
Rail 954 (ACSR) 45/7 Stranding	50 75 100	740 1130 1346	735 1133 1349	716 1104 1313	690 1118 1338	616 1062 1293
Drake 795 (ACSR) 26/7 Stranding	50 75 100	676 1030 1227	671 1033 1229	655 1006 1197	631 1019 1219	564 968 1179
Grosbeak 636 (ACSR) 26/7 Stranding	50 75 100	591 890 1060	586 894 1061	572 870 1034	551 881 1053	495 838 1017
Dove 556.5 (ACSR) 26/7 Stranding	50 75 100	545 818 972	540 820 973	527 798 947	508 809 965	458 769 932
Hen 477 (ACSS) 30/7 Stranding	150	1099	1098	1069	1093	1065
Hawk 477 (ACSR) 26/7 Stranding	50 65 75 100	495 663 740 879	491 664 741 880	480 649 722 856	463 653 732 873	418 615 696 843
Lark 397.5 (ACSS) 30/7 Stranding	200	1114	1108	1082	1105	1083
Ibis 397.5 (ACSR) 26/7 Stranding	50 75 100	442 657 781	438 659 781	429 642 759	414 650 774	375 619 748
Linnet 336.4 (ACSR) 26/7 Stranding	50 75 100	399 590 700	395 591 700	387 576 680	374 583 694	339 555 670
Partridge 266.8 (ACSR) 26/7 Stranding	50 75 100	345 508 602	343 510 601	336 495 584	324 502 597	295 479 576
Penguin 4/0 (ACSR) 6/1 Stranding	50 75 100	286 405 466	284 406 465	280 394 455	270 400 462	246 382 446
Quail 2/0 (ACSR) 6/1 Stranding	50 100	217 352	216 352	213 342	206 350	188 337

Table C2
Tri-State Overhead Conductor Emergency Ratings
(Percent of Static Rating)

Conductor Type	15 Min Percent Overload	30 Min Percent Overload
Falcon 1590 (ACSR) 54/19 Stranding	112	103
Pheasant 1272 (ASCR) 54/19 Stranding	109	102
Bittern 1272 (ASCR) 45/7 Stranding	108	102
Cardinal 954 (ACSR) 54/7 Stranding	107	101
Rail 954 (ACSR) 45/7 Stranding	106	101
Drake 795 (ACSR) 26/7 Stranding	106	101
Grosbeak 636 (ACSR) 26/7 Stranding	104	100
Dove 556.5 (ACSR) 26/7 Stranding	103	100
Hen 477 (ACSS) 30/7 Stranding	103	100
Hawk 477 (ACSR) 26/7 Stranding	103	100
Lark 397.5 (ACSS) 30/7 Stranding	102	100
Ibis 397.5 (ACSR) 26/7 Stranding	102	100
Linnet 336.4 (ACSR) 26/7 Stranding	101	100
Partridge 266.8 (ACSR) 26/7 Stranding	101	100
Penguin 4/0 (ACSR) 6/1 Stranding	101	100
Quail 2/0 (ACSR) 6/1 Stranding	100	100

Table C3
Tri-State Terminal Equipment Emergency Ratings
(Percent of Nameplate Continuous Rating)

Terminal Equipment	**30 Min Percent Overload**	**4 Hour Percent Overload**
Power Transformers	125	110
Circuit Breakers	119	112
Current Transformers	170	119
Disconnect Switches	122	122
Wave Traps	129	100

APPENDIX D: REQUIREMENTS FOR GENERATOR INTERCONNECTIONS

Tri-State Generation and Transmission Assoc. (TP) –Requirements for Generator Interconnections

A. Tri-State's Steady State VAR, and Voltage Regulation Requirements:

1. The generating facility (GF) must be capable of either producing or absorbing VAR to achieve a 0.94 power factor (pf) as measured at the high-side of the generator substation across the range of near 0% to 100% of facility MW rating under normal operating voltage conditions, 0.95-1.05 per unit voltage, at the POI.
2. The GF may be required to either produce VAR or absorb VAR from .90 per unit to 1.10 per unit voltage at the POI, with typical target regulating voltage range being 1.01-1.03 per unit voltage.
3. The GF must operate in the automatic voltage control mode, regulating voltage at the POI.
4. Small voltage disturbances within the continuous operating range must be responded to within 500 ms of the disturbance. The GF may be required to reach 90% of its final reactive power output within 10 seconds. An overshoot of 5% of rated reactive power is permitted.
5. Large voltage disturbances beyond the continuous operating range must be responded to within 16 ms (one cycle). The GF may be required to reach 90% of its final reactive power output within 100 ms.
6. The power factor range for the GF at the high-side of the generator substation shall be dynamic and can be met using, for example, power electronics designed to supply dynamic reactive support, fixed/switched capacitors, or a combination of the two.
7. The GF may utilize switched capacitors or reactors as long as the individual step size results in less than 3% change at the POI operating bus voltage. This step change voltage magnitude shall be calculated based on the minimum system (N-1) short circuit POI bus MVA level as supplied by Tri-State.
8. When the GF is not producing any real power (near 0 MW), the VAR exchange at the POI shall be less than 2 MVAR, i.e., VAR neutral.
9. All generator interconnections are subject to additional detailed study, as may be required, utilizing more complex models and software such as PSCAD, or similar, and may require mitigation in excess of minimums imposed by published standards.

B. Tri-State's Dynamic VAR and Low Voltage Ride-Through Requirements:

1. The generating facility must be able to meet dynamic response LVRT requirements consistent with the latest NERC/WECC criteria and Tri-

State's Generator Interconnection Procedures (Appendix G) and consistent with FERC Order 661a.

2. Generating facilities are required to remain in service during three-phase and single line-to-ground (SLG) faults with normal clearing times of approximately 4 to 9 cycles, and SLG faults with delayed clearing and subsequent post-fault voltage recovery to pre-fault voltage, unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the circuit breaker clearing times of the affected system to which the facilities are interconnecting. The maximum clearing time the generating facilities shall be required to withstand for a fault shall be 9 cycles. After which, if the fault remains following the location-specific normal clearing time for faults, the generating facilities may disconnect from the transmission system. Generation shall remain interconnected during a fault on the transmission system for a voltage level as low as zero volts as measured at the POI. The customer may not disable low voltage ride through equipment while the generation is on-line.

3. This requirement does not apply to faults that may occur between the generator terminals and the POI.

4. Generating facilities may meet the LVRT requirements by the performance of the generators or by installing additional equipment, such as static VAR compensators, or by a combination of generator performance and additional equipment.

5. Momentary cessation, also referred to as "blocking," is when no current is injected into the grid by the inverter during low or high voltage conditions outside the continuous operating range. BPS-connected inverter-based resources are expected to continue current injection inside the "No Trip" zone of the frequency and voltage ride through curves of PRC-024-2. Existing and newly interconnecting inverter-based resources should eliminate the use of momentary cessation to the greatest possible extent.

6. The GF may not trip or cease to inject current during loss of synchronism, unless the phase lock loop is unable to regain synchronism after 150 ms.

C. Tri-State's Frequency Response Requirements:

1. The generating facility must be able to perform power-frequency control. The GF must respond to frequency deviations of 0.036 Hz or greater, and adjust output in accordance to a maximum of 5% droop.

2. Frequency deviations must be responded to within 500 ms, and achieve 90% of its final active power output within 4 seconds.

3. Active power output must overshoot the final power output by 5% of rated power or less. Within 10 seconds of the frequency deviation, active power output must settle to within 2.5% of rated power of its final output.
4. The GF is not required to reserve generation headroom for frequency response. If no generation headroom is reserved, the GF is still required to reduce generation during overfrequency events.
5. The GF may be required to provide sustained or unsustained Fast Frequency Response.
6.

APPENDIX E: VOLTAGE FLUCTUATION AND FLICKER CRITERIA

Overview

The following criteria define Tri-State's maximum acceptable levels of voltage fluctuation and light flicker in power systems caused by motor starting and other advanced power electronic devices. These criteria are not applicable to voltage transients and other infrequent, short-term disturbances from typical transmission system operations.

These criteria should be used both during operations and during the planning and design of new additions to the power system. Flicker meters are not typically installed throughout the system. Customer complaints are usually the first indication of a potential problem.

Tri-State's criteria are applicable to Tri-State owned distribution, sub-transmission, and transmission bus voltages.

Adherence to flicker criteria will be based on voltage measurements made with IEEE 1453 compliant flicker meters.

Voltage Fluctuations

Tri-State's voltage fluctuation limits are applicable to events that occur less than once an hour, based on a weekly average. Capacitor switching and large motor starting are the most common causes of voltage fluctuation.

Voltage fluctuation is the per-unit step change in voltage from pre-event to the lowest measured point in voltage during the switching or motor starting event. The system intact (N-0) limits are shown in Table E1 below. Voltage fluctuation may exceed these limits under prior outage conditions.

Table E1
Voltage fluctuation criteria

Voltage Level	Maximum Allowable Voltage Fluctuation
< 100 kV	0.06 p.u.
≥ 100 kV	0.03 p.u.

Flicker Criteria

Flicker criteria are applicable to events that occur more frequently than once an hour. These criteria are based on measurements taken by a flicker meter.

Modern, IEEE 1453-2004 compliant, flicker meters measure voltage fluctuations and consider the frequency and magnitude of change, how abruptly the voltage change occurs, and the human sensitivity to the corresponding change in light. The standard outputs for an IEEE 1453 compliant flicker meters are called "Short Term Perception of Flicker (Pst)" and "Long Term Perception of Flicker (Plt)." Pst is obtained over a 10 minute period and Plt is determined over a two-hour period.

Tri-State's limits for flicker are based on measurements from IEEE 1453 compliant flicker meters and are shown below on Table E2 below.

Table E2
Flicker criteria

Measurement	**≤ 1 kV**	**1 kV – 35 kV**	**> 35 kV**
Short Term Perception of Flicker (P_{st})	1.0	0.9	0.8
Long Term Perception of Flicker (P_{lt})	0.8	0.7	0.6

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APPENDIX G: TRANSMISSION TRANSFER CAPABILITY ASSESSMENT

Transmission Transfer Capability Assessment Practices

Tri-State has the capability of moving electric power throughout the region using the transfer capability of its transmission lines. Transfer capability is a measure of the ability of interconnected electric systems to reliably move power from one area to another. The transfer capability of a bulk transfer path is the total megawatt flow capability along a path. Currently, Tri-State has capacity rights in six bulk transfer paths, and uses this capacity for bulk power transfers. A bulk transfer path may, or may not, be an actual boundary determined by an electrical limitation. This electric limitation may be internal to one control area, and can be monitored by system operators to assist in dispatching electricity. Ratings have been established for those paths, and are recognized by WECC. The WECC Path Rating Catalog identifies many transmission paths including the operating restrictions and limitations for each. These limitations and restrictions have been determined by joint studies performed by WECC Members. The WECC facility rating document, "Procedures for Regional Planning Project Review and Rating Transmission Facilities", presents a methodology for rating the transmission facilities and bulk transfer paths. Each of these two documents is available through WECC. The bulk transfer paths in Tri-State's area are:

Path Name	Facilities Comprising Path
TOT 1A	Craig-Bonanza 345 kV
Colorado - Utah	Hayden-Artesia 138 kV
	Meeker-Rangely 138 kV
TOT 2A	Hesperus-San Juan 345 kV
SW Colo. – New Mexico	Hesperus-Glade Tap 115 kV
	Lost Canyon-Shiprock 230 kV

TOT 3	Archer-Ault 230 kV
SE Wyo. – Colo.	Laramie River-Ault 345 kV
	Laramie River-Keota 345 kV
	Cheyenne-Owl Creek 115 kV
	Sidney-Sterling 115 kV
	Sidney-Spring Canyon 230 kV
	Terry Ranch Road-Ault 230 kV
TOT 4B	CarrDraw-Buffalo 230 kV
Northwest Wyoming	Tongue River-Sheridan 230 kV
	Spence-Thermopolis 230 kV
	Alcova-Raderville 115 kV
	Casper-Midwest 230 kV
	Riverton-Thermopolis 230 kV
	Riverton-230/115 kV transformers
TOT 5	North Park-Terry Ranch Road 230 kV
West Colo. – East Colo.	Craig-Ault 345 kV
	Hayden-Gore Pass 230 kV
	Hayden-Gore Pass 138 kV
	N. Gunnison-Salid (Poncha Jct.) 115 kV
	Curecanti-Poncha 230 kV
	Basalt-Malta 230 kV
	Hopkins-Malta 115 kV
NM 1	West Mesa-Arroyo 345 kV
Central NM	Springerville-Luna 345 kV
– Southern NM	Greenlee-Hidalgo 345 kV
	Belen-Bernardo 115 kV

NM 2	Four Corners-Rio Puerco 345 kV
Into Central NM	San Juan-Rio Puerco 345 kV
	San Juan-Jicarilla 345 kV
	McKinley/YahTaHey345/115 kV Transformers
	Bisti-Ambrosia 230 kV
	Walsenburg-Gladstone 230kV
	Less these flows:
	Belen-Bernardo 115 kV
	West Mesa-Arroyo 345

The potential impact of DC Tie Schedules in both directions must be considered as well. There are DC-ties located at Stegall, Sidney, and Lamar buses. Bulk transfer path ratings must be kept within limits established by approved studies. For more information on bulk transfer ratings listed above, contact information is listed with each accepted bulk transfer path rating in the latest WECC Path Rating Catalog.

Tri-State Generation and Transmission Association, Inc. Open Access Transmission Tariff
Filing Category: New Filing Date: 12/26/2019
FERC Docket: ER20-00686-000 FERC Action: Accept
FERC Order: 170 FERC ¶ 61,222 Order Date: 03/20/2020
Effective Date: 02/25/2020 Status: Effective
Attachment K, Transmission Planning Process, 1.0.0

ATTACHMENT K

Transmission Planning Process

I. Overview of Tri-State Transmission Planning Process

Tri-State Generation and Transmission Association, Inc. (Tri-State) is an electric power cooperative operating on a not-for-profit basis that generates and transmits electricity to its member rural electric cooperatives and public power districts in Colorado, Nebraska, New Mexico and Wyoming. Tri-State is a public utility that provides Point-to-Point (PTP) and Network Integration Transmission Service (NITS) under an Open Access Transmission Tariff (OATT or Tariff).

Tri-State's transmission planning process is based on the following three core objectives:

- Maintain safe, reliable, affordable, and responsible electric service to its members, consistent with its obligations under federal and state law.
- Improve the efficiency of electric system operations, including the provision of open and non-discriminatory access to the transmission facilities under its control.
- Identify and promote new investments in transmission infrastructure in a coordinated, open, transparent and participatory manner.

Tri-State's transmission planning process is intended to facilitate the timely and coordinated development of transmission infrastructure that both maintains system reliability and meets

Transmission Customer needs, while continuing to provide reliable, affordable, and responsible electric power to its members.

The Tri-State planning process includes an annual open planning meeting to permit all interested parties, including NITS and PTP Transmission Customers, interconnecting neighboring transmission providers, regulatory agencies, and all other stakeholders, to provide input into and comment on Tri-State's transmission plan.

Tri-State coordinates its planning process with other transmission providers and stakeholders at the regional and subregional levels of the Western Interconnection through its active participation in the Colorado Coordinated Planning Group (CCPG), the Southwest Area Transmission Planning (SWAT) group, membership in WestConnect, and membership in the Western Electricity Coordinating Council (WECC).

Three subregional planning groups operate within the WestConnect footprint: the Colorado Coordinated Planning Group (CCPG), the Southwest Area Transmission Planning (SWAT) group and the Sierra Coordinated Planning Group (Sierra). WestConnect's planning effort, which includes funding, planning management, analysis, report writing and communication services, supports and manages the coordination of the subregional planning groups and their respective studies. These responsibilities are detailed in the WestConnect Project Agreement for Subregional Transmission Planning (the WestConnect STP Project Agreement) dated May 23, 2007. A copy of the STP Project Agreement is available at www.westconnect.com. Tri-State is a signatory to the WestConnect Project Agreement.

The subregional planning groups within the WestConnect footprint, assisted by the WestConnect planning manager, coordinate with other Western Interconnection transmission providers and their subregional planning groups as explained in section III of this document.

II. Tri-State Local Transmission Planning

Participation in Tri-State's local planning process is open to all interested parties, including but not limited to, all NITS and PTP Transmission Customers, interconnecting neighboring transmission providers, regulatory agencies, and other stakeholders.

A. General Provisions for Tri-State Local Transmission Planning Process

1. Purpose of Local Transmission Planning Studies

   Tri-State's local transmission planning process is designed to meet the following needs:

   a. Provide adequate transmission to access sufficient resources in order to reliably and economically serve Tri-State's member and other Transmission Customer's loads.

   b. Support Tri-State's members' sub-transmission and distribution systems.

   c. Provide for interconnection of new generation resources.

   d. Coordinate new interconnections with other transmission systems.

   e. Accommodate requests for long-term transmission access.

   f. Consider local transmission needs for economic upgrades to address congestion.

   g. Consider local transmission needs driven by Public Policy Requirements.

2. Types of Local Transmission Planning Studies

   a. *Local Reliability Studies*. Tri-State will conduct reliability studies to ensure that all NERC, WECC, and local reliability standards are met for each year of the ten-year planning horizon, including all Transmission Customer-planned loads and resources. These reliability studies will be coordinated with the other regional transmission planning organizations through the CCPG, WestConnect, and WECC study efforts.

b. *Generator Interconnection Studies*. Tri-State will perform, or cause to be performed, system interconnection studies at the request of an Interconnection Customer under the terms and conditions specified in the Large Generator Interconnection Procedures (LGIP) and Small Generator Interconnection Procedures (SGIP) of Tri-State's OATT.

c. *Economic Studies*. The purpose of economic planning studies is to identify significant and recurring congestion on Tri-State's 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 or/and loads.

d. *Public Policy Requirements*. For purposes of this Attachment K, "Public Policy Requirements" means those requirements enacted by state or federal laws or regulations, including those enacted by local governmental entities, such as a municipality or county. Public Policy Requirements, as applicable, are incorporated into the load and resource forecasts provided by Transmission Customers and/or are modeled in the local planning studies.

3. <u>Confidential or Proprietary Information</u>

Tri-State's transmission planning studies may include base case data that are WECC proprietary data or classified as Critical Energy Infrastructure Information ("CEII") by the Federal Energy Regulatory Commission ("FERC" or "Commission"). Tri-State maintains base power flow, stability and short circuit databases, including all underlying assumptions, and contingency lists on a password-protected website, subject to confidentiality provisions. Such network models and underlying assumptions reasonably represent current system conditions. Stakeholders are required to sign a confidentiality agreement prior to the release of commercially sensitive information or CEII. A Stakeholder must also hold membership in, or execute a non-disclosure agreement with, WECC in order to obtain requested base case data from Tri-State. Tri-State will not provide confidential information belonging to third parties without obtaining the consent of the third parties.

4. Transmission Planning Cycle

Tri-State conducts its transmission planning on a calendar year cycle for a ten-year planning horizon. Tri-State updates its ten-year plan annually and provides summaries of its transmission plans at Stakeholder meetings. The ten-year plan results are summarized in the WestConnect Annual Ten-Year Transmission Plan, which is posted to the WestConnect website. In addition, Tri-State files a listing of significant projects with the Colorado Public Utilities Commission at the end of April each year as required by Rule 3206. Tri-State also biennially files a summary of its transmission plans for the state of Colorado in accordance with the requirements of the Colorado Public Utilities Commission Rule 3627.

5. Transmission Customer's Responsibility for Providing Data

a. *Use of Customer Data*. Tri-State uses the information provided by its Transmission Customers to, among other things, assess network loads and resources, identify transmission needs and operating dates, and to update regional models used to conduct planning studies.

b. *Submission of Data by NITS Customers*. Pursuant to Tri-State's OATT, NITS Transmission Customers are required to submit ten-year projected loads and resources to Tri-State on an annual basis. Such information is to be submitted by October 1st of each year to be included in the following year's planning process.

c. *Submission of Data by Other Transmission Customers*. In order to provide the most accurate planning models, it is essential that all other Transmission Customers provide their ten-year load and resource needs for inclusion in the Tri-State transmission planning process. This information must be submitted by October 1st of each year in order to be included in the following year's planning process.

d. *Transmission Customer Data to be Submitted*. To the maximum extent practical and consistent with protection of proprietary or confidential information, data submitted by Network and Point-to-Point Transmission Customers and other Transmission Customers shall include the following information for the ten-year planning horizon:

i. Generators – planned additions or upgrades (including status and expected in-service dates), planned retirements and any environmental restrictions.

ii. Demand response resources – existing and planned demand response resources and their impacts on demand and peak demand.

iii. Network Transmission Customers – forecast information for load and resource requirements over the planning horizon and identification of demand response reductions. Forecast information shall address Public Policy Requirements.

iv. Point-to-Point Transmission Customers – projections of need for service, including transmission capacity, duration of service and points of receipt and delivery.

Each Transmission Customer is responsible for submitting timely written notice to Tri-State of material changes in any of the information previously provided related to the Transmission Customer's load, resources, or other aspects of its facilities or operations which may, directly or indirectly, affect Tri- State's ability to provide service.

6. <u>Stakeholder Participation and Public Meetings</u>

a. <u>Purpose and Scope</u>

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: Colorado Public Utilities Commission

Rule 3627 specific meetings and stakeholder communications; FERC Order No. 890 specific meetings and communications; project-specific meetings and communications; and CCPG participation.

In addition to larger stakeholder meetings addressing system-wide transmission projects, Tri-State also conducts a number of meetings related to individual proposed transmission projects. These meetings and other project-related communications include 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 is generally dependent on the development status of the project.

Details of Tri-State's larger stakeholder meetings, including invitation lists, attendees, questions and comments received together with Tri-State's responses thereto, and relevant presentations can be found on the Tri-State company website.

Tri-State will conduct at least one open public planning meeting each year that will allow stakeholders to participate in Tri-State's transmission planning process. The public transmission planning meetings will be open to all stakeholders. The meetings will provide an open, transparent forum whereby electric transmission stakeholders can comment and provide input to Tri-State during the transmission planning process. These public transmission planning meetings will serve to:

i. Promote discussion of all aspects of the Tri-State transmission planning activities, including, but not limited to, methodology, study inputs, public policy requirements, study results, and alternative solutions.

ii. Provide a forum for Tri-State to better understand the specific electric transmission interests of all stakeholders.

b. Public Meeting Process

At such meetings Tri-State shall: (a) review its transmission planning process and current study plan with stakeholders; (b) receive transmission study requests from stakeholders for review and discussion; (c) solicit information from its Transmission Customers on loads and resources and other needs, such as public policy requirements, for the preparation of its ten-year plan; and (d) provide updates on its planned projects.

c. Meeting Notices, Documents, and Communications

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 typically included in Tri-State's Transmission Plan are 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 will include agencies such as parks and school districts.

Contact lists for non-governmental stakeholders are 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 includes stakeholders identified as being interested in specific proposed projects. The resulting non-governmental stakeholders includes other utilities, Tri-State members, energy and transmission project developers, environmental groups, economic development organizations, various advocacy groups, and elected officials not already included in the governmental outreach communications.

Meeting notices, including date, time, place and meeting agenda, will be posted on the Tri-State company website as well as the WestConnect website. Tri-State will establish and post its public planning meeting schedule at least once annually.

The agendas for Tri-State's public planning meetings will be sufficiently detailed, posted on the Tri-State company website, the WestConnect website, and circulated to its distribution list in advance of the meetings in order to allow Transmission Customers and stakeholders the ability to choose their meeting attendance most efficiently.

Tri-State will post all meeting-related notes, documents and drafts or final reports on its company website.

7. Planning Criteria, Methodology, and Planning Study Results

Tri-State's engineering methodologies and criteria used in planning its transmission system are documented in Tri-State's Engineering Standards Bulletin, which can be found on the Tri-State company website as well as OASIS.

Tri-State's biennial 10-year transmission plan filed with the Colorado PUC in accordance with Rule 3627 is posted on the company website as well.

8. Comparability and Evaluation of Alternative Solutions

Tri-State recognizes that its Transmission Customers need to address transmission system requirements to meet Reliability Standards, Public Policy Requirements, which include state renewable portfolio/carbon reduction standards or goals, state resource adequacy and demand response requirements, and other similar regulatory programs that could include treatment of customer demand response resources. Tri-State shall consider verified demand response, if available, when evaluating transmission project alternatives in the local study planning process. Tri-State shall consider alternative solutions to address these needs from sponsors of transmission, generation and demand resources. In particular, alternative solutions shall be evaluated against each other based on a comparison of their effectiveness of performance and relative economics. In evaluating alternatives, including demand responses and transmission alternatives, Tri-State shall evaluate alternatives on the basis of: (1) ability to mitigate any criteria or NERC Reliability Standard issues; (2) ability to mitigate those issues over the time frames of the study; (3) comparison of the capital costs of the demand response, as compared to other transmission alternatives; (4) the technical, financial and operational feasibility of any proposed alternatives; and (5) comparison of any operational benefits or issues between demand responses or transmission alternatives. From this comparison, the most appropriate project alternative can be selected.

B. Local Reliability Transmission Planning Study 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 Transmission Customer needs, while continuing to provide reliable, affordable, and responsible electric power to its members.

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

Maintaining safe, reliable, affordable, and responsible electric service to its members

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, and coordinated regional planning principles.

Internally, and through WestConnect and CCPG, Tri-State 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 Local Planning Process, a wide range of factors and interests are considered by Tri-State as part of its reliability assessment, including, but not limited to: (i) the needs of Transmission Customers to integrate loads and resources; (ii) transmission infrastructure upgrades necessary to interconnect new generation resources; (iii) the minimum reliability standard requirements promulgated by NERC and WECC; (iv) bulk electric system considerations above and beyond the NERC and WECC minimum reliability standard requirements; (v) transmission system operational flexibility, which supports economic dispatch of interconnected generation resources; and (vi) various regional and sub-regional transmission projects planned by other utilities and stakeholders.

This comprehensive internal, regional, and sub-regional planning process ensures that Tri-State's local reliability needs are carefully coordinated with all stakeholders.

C. Economic Transmission Planning Study Process

Tri-State shall facilitate priority Local Economic Planning Studies for the Tri-State transmission system, pursuant to the procedures described below. Regional Economic Planning Studies shall be performed by WestConnect, pursuant to Part III of this Attachment.

Requesting Economic Planning Studies

Any Tri-State Transmission Customer or other stakeholder, including sponsors of transmission solutions, generation solutions and solutions utilizing demand response resources ("Requester"), may submit a study request for an economic planning study directly to Tri-State or WestConnect. Requests submitted to WestConnect will be processed pursuant to Part III of this Attachment.

For requests submitted to Tri-State, the Requester must submit its study request(s) no later than September 1 each year for the study request(s) to be reviewed by Tri-State and discussed with stakeholders at the next open meeting of that year. All such economic planning study requests must be submitted via email to Tri-State (transmissionplanning@tristategt.org).

Economic planning study requests that are developed by Tri-State by September 1 of any year also shall be discussed with stakeholders at the next open meeting of that year. Tri-State shall coordinate the timing of its economic planning study cycle with the WestConnect processes.

2. Process for Handling Economic Transmission Planning Study Requests Received by Tri-State

   a. Review of Economic Transmission Study Requests. All economic planning study requests received by September 1 shall be reviewed by Tri-State prior to the next open planning meeting. Tri-State shall seek stakeholder input on those requests at the next open planning meeting. At the meeting, Tri-State shall state which requests it has determined are local. Based on stakeholder input, Tri-State shall then choose whether the local study requests should be considered a local priority request and facilitated by Tri-State. If Tri-State has determined that the study request is regional or interregional, Tri-State shall transfer the request to WestConnect.

   b. Criteria Used to Determine Whether an Economic Planning Study Request is a Local Economic Planning Study Request. Based in part on the number and type of economic planning study requests received, Tri-State shall consider the following criteria to determine if the study request is for a local economic planning study or a regional economic planning study:

i. Whether the study request affects the interconnected transmission system or only Tri-State's transmission system.

ii. Whether the potential remedies are confined to and only resolvable within Tri-State's local transmission system.

c. Criteria Used to Determine Whether a Local Economic Planning Study Request is a Priority Request. Tri-State shall consider the following criteria to determine whether a Local Economic Planning Study request is a priority request:

i. Which portion(s) of the Tri-State local transmission system shall be under consideration in the study.

ii. Whether the request raises fundamental design issues of interest to multiple parties.

iii. Whether the request raises policy issues of national, regional, or state interest, e.g., with respect to access to renewable power, and location of both conventional and renewable resources.

iv. Whether the objectives of the study can be met by other existing or planned studies.

v. Whether the study shall provide information of broad value to Transmission Customers, regulators, transmission providers and other interested Stakeholders.

vi. Whether similar requests for studies or scenarios can be represented generically if the projects are generally electrically equivalent.

vii. Whether requests can be aggregated into energy or load aggregation zones with generic transmission expansion between them.

viii. Whether the study request requires the use of production cost simulation or whether it can be better addressed through technical studies, i.e., power flow and stability analysis.

d. Priority Local Economic Planning Study Requests. If Tri-State determines that a Local Economic Planning Study request is a priority local request, Tri-State shall facilitate the study and coordinate assumptions and results with its Transmission Customers, stakeholders, and interconnected transmission providers. Tri-State shall have no obligation to facilitate more than three priority Local Economic Planning Studies per calendar year. Tri-State reserves the right to reasonably limit the scope of the priority Local Economic Planning Studies, based on the cohesiveness of the study request as a single study, likely public merit addressing congestion and/or integration of new resources and loads on an aggregated basis, and study cost. If Tri-State receives more than three requests for Local Economic Planning studies that are determined to be priority local requests, stakeholders and Tri-State shall prioritize the requests to determine which three Tri-State shall facilitate. Tri-State may facilitate one or more additional studies (beyond three) at its sole discretion. If Tri-State elects not to perform such additional studies, Tri-State may assist the Requester in having a third party perform the Local Economic Planning Study at the Requester's expense. Tri-State shall assist the Requester (or such third party) , at the Requestor's expense, in ensuring that the study is coordinated as necessary through local, regional, or interregional planning groups.

3. Low Priority Economic Study Requests

If Tri-State determines, after review through an open stakeholder process, that a requested Local Economic Planning Study is not a priority study, the Requester may request Tri-State's assistance in having a third party perform the Local Economic Planning Study analysis at the Requester's expense. Tri-State shall have no obligation to fund any low priority Local Economic Planning Study. Tri-State shall assist the Requester, at the Requestor's expense, in ensuring that the study is coordinated as necessary through local or regional planning groups.

4. <u>Clustering Priority Local Economic Planning Studies</u>

Priority Local Economic Planning Studies may be studied in clusters. Tri-State may decide to study any number of Local Economic Planning Studies together, either on its own initiative, upon the request of a Requester, or to comply with state regulatory requirements, if applicable. Tri-State shall combine such studies as it deems appropriate. Tri-State shall use the following processes to determine whether to cluster priority Local Economic Planning Studies:

Tri-State-Proposed Clusters

In the event that Tri-State proposes to cluster certain priority Local Economic Planning Studies on any reasonable grounds, including, without limitation, upon its determination that the proposed cluster studies are sufficiently similar, from an electrical perspective, to be feasibly and meaningfully studied as a group, it shall provide notice to each Requester whose study it proposes to include in the cluster study. Each Requester shall be provided the opportunity to opt out of the cluster within ten (10) calendar days of written notice from Tri-State.

b. Requester-Proposed Clusters

If a Requester wishes to propose a Local Economic Planning cluster study, prior to submitting the Local Economic Planning Study cluster request to Tri-State, the Requester must contact all of the other Requesters whose requests it proposes to cluster and obtain their written consent that they are willing to have their request clustered with other identified requests. All such written consent(s) must be provided to Tri-State before Tri-State shall commence a Local Economic Planning cluster study. Tri-State shall reasonably determine whether the Local Economic Planning Study requests that the Requester proposes to cluster and for which the other affected Requesters have provided consent, are sufficiently similar, from an electrical perspective, to be feasibly and meaningfully studied together. Tri-State reserves the right to reject a Requester-proposed cluster on any reasonable grounds, including, without limitation, upon Tri-State's determination that the proposed cluster cannot be feasibly studied as a group, is not likely to provide a result significantly different than separate studies, or if the proposed clustering impairs administration or timely processing of the Local Economic Planning Study process. Tri-State shall make the determination whether to reject a proposed cluster, and provide notice of any decision to reject, within twenty (20) calendar days of receipt of all of the written consents of the Requesters that propose to be clustered.

5. Cost Responsibility for Economic Planning Studies

a. Priority Local Economic Planning Studies

Tri-State shall facilitate, at Tri-State's cost, up to three priority Local Economic Planning Studies per calendar year. Each of the clustered priority Local Economic Planning Studies shall be deemed to be a single study. Tri-State shall have no obligation to facilitate more than three priority Local Economic Planning Studies per calendar year. For Local Economic Planning Studies not selected, Tri-State may assist the Requester in having a third party perform the Local Economic Planning Study at the Requester's expense.

b. Priority Regional Economic Planning Studies

Priority Regional Economic Planning Studies will be performed by WestConnect.

Other Local Economic Planning Study Requests

To the extent Requesters of Local Economic Planning Studies not selected to be performed at Tri-State's cost pursuant to this section wish to have those studies performed, such Local Economic Planning Study requests shall be performed at the Requester's expense. Tri-State may assist the Requester in finding a third party to perform the studies.

6. Exchange of Data Unique to Local Economic Planning Studies

a. Data Used for Local Economic Planning Studies

Tri-State obtains all data used for its local economic planning studies from the WestConnect data base.

b. Request for Base Case Data

Any Requester's request for detailed base case data must be submitted to WECC in accordance with the WECC procedures.

c. Posting of Requests for Local Economic Planning Studies

All requests made to Tri-State for economic planning studies and responses to such requests shall be posted on the Tri-State OASIS and the WestConnect website, subject to confidentiality requirements.

7. Tri-State Point of Contact for Study Requests

Stakeholder questions regarding modeling, criteria, assumptions, and data underlying economic planning studies should be submitted via email to Tri-State (transmissionplanning@tristategt.org).

D. Public Policy Requirement Transmission Planning Study Process

1. Procedures for Identifying Transmission Needs Driven by Public Policy Requirements

Stakeholders may participate in identifying local transmission needs driven by Public Policy Requirements by participating in any one of Tri-State's outreach efforts for stakeholder participation as described in II.A.6 above.

In order to identify transmission needs driven by Public Policy Requirements, Tri-State will consider several factors, including but not limited to:

i. Whether the Public Policy Requirement is driving a local transmission need that can be reasonably identified in the current planning cycle;

ii. The feasibility of addressing the local transmission need driven by the Public Policy Requirement in the current planning cycle;

iii. The basis supporting the local transmission need driven by the Public Policy Requirement; and

iv. Whether a Public Policy Requirement has been identified for which a local transmission need has not yet materialized, or for which there may exist a local transmission need but the development of a solution to that need is premature.

No single factor shall necessarily be determinative in selecting among the potential transmission needs driven by Public Policy Requirements.

2. Procedures for Evaluating Solutions to Identified Transmission Needs Driven by Public Policy Requirements

Stakeholders may provide comments on proposed solutions or may submit other proposed solutions to local transmission needs.

The procedures for evaluating potential solutions to the identified local transmission needs driven by Public Policy Requirements are the same as those procedures used to evaluate any other project proposed in the local planning process.

3. Posting of Public Policy Needs

Tri-State will maintain on its OASIS:

i. A list of all local transmission needs identified that are driven by Public Policy Requirements and that are included in the studies for the current local planning cycle; and

ii. An explanation of why other suggested transmission needs driven by Public Policy Requirements were not evaluated.

III. Regional Transmission Planning Process

This Section of Attachment K to the Tri-State OATT implements the requirements for regional planning set forth in Federal Energy Regulatory Commission Order Nos. 890

and 1000. Tri-State engages in regional planning and coordination within the WestConnect regional process (Regional Planning Process), which also includes Tri-State's participation in interregional planning in the United States portion of the Western Interconnection through its participation in WestConnect.

The purpose of the Regional Planning Process is to produce a regional transmission plan (the Regional Plan) and provide a process for evaluating projects submitted for cost allocation in accordance with the provisions of this Attachment K and those business practices adopted by WestConnect in the WestConnect Regional Planning Process Business Practice Manual, as may be amended from time to time, available on the WestConnect website (Business Practice Manual).

A. Overview

The WestConnect Planning Region is defined by the Transmission Owners and Transmission Provider members (referred to generally as Transmission Owners) participating in the Regional Planning Process and for whom WestConnect is conducting regional planning. The service areas of the Transmission Owners consist of all or portions of nine states: Arizona, California, Colorado, Nebraska, New Mexico, Nevada, South Dakota, Texas and Wyoming. Non-public utilities are invited to participate in the Regional Planning Process.

The WestConnect Order No. 1000 regional transmission planning management committee (the Planning Management Committee or PMC) will be responsible for administering the Regional Planning Process. In order to align its regional process with the western interregional coordination process, WestConnect began its biennial process in 2016. WestConnect conducted an abbreviated planning process in 2015.

In conjunction with creating the new PMC, the WestConnect members, in consultation with interested stakeholders, have established a separate project agreement (the Planning Participation Agreement) to permit interested stakeholders to participate in the Regional Planning Process. Although the Regional Planning Process is open to the public, stakeholders interested in having a voting right in decisions related to the Regional Planning Process will be required to execute the Planning Participation Agreement and any necessary confidentiality agreements. The PMC will implement the stakeholder-developed Regional Planning Process, which will result in a Regional Plan for the ten-year transmission planning horizon.

Tri-State is a party to the WestConnect STP Project Agreement. The committees formed under the WestConnect STP Project Agreement and the WestConnect Steering Committee have no authority over the PMC and the PMC's decision making in implementing the Regional Planning Process.

1. WestConnect Planning Participation Agreement

Each WestConnect member will be a signatory to the Planning Participation Agreement, which formalizes the members' relationships and establishes obligations, including Transmission Owner coordination of regional transmission planning among the WestConnect participants and the local transmission planning processes, and producing a Regional Plan.

2. Members

WestConnect has two types of members: (i) Transmission Owners that enroll in the WestConnect Planning Region in order to comply with Order No. 1000 planning and cost allocation requirements, as well as Transmission Owners that elect to participate in the WestConnect Regional Planning Process without enrolling for Order No. 1000 cost allocation purposes, and (ii) stakeholders who wish to have voting input into the methodologies, studies, and decisions made in the execution of those requirements.

A Transmission Owner that wishes to enroll or participate in the WestConnect Planning Region may do so by executing the Planning Participation Agreement and paying its share of costs as provided for in the Planning Participation Agreement.

A stakeholder that wishes to have voting input may join the WestConnect Planning Region by executing the Planning Participation Agreement, paying annual dues, and complying with applicable provisions as outlined in such agreement. For further information regarding membership dues, please see WestConnect's Planning Participation Agreement, located at www.westconnect.com and on file with FERC.

b. Exiting the WestConnect Planning Region

Should a Transmission Owner member wish to exit the WestConnect Planning Region, it must submit notice in accordance with the Planning Participation Agreement and pay its share of any WestConnect expenditures approved prior to providing its formal notice of withdrawal from the WestConnect Planning Region.

Should a stakeholder wish to exit the WestConnect Planning Region, it may do so by providing notice in accordance with the Planning Participation Agreement. Withdrawing stakeholders will forfeit any monies or dues paid to the PMC and agree to remit to the PMC any outstanding monies owed to WestConnect prior to their withdrawal being considered official.

c. List of Enrolled Entities

Transmission Owners enrolled in the WestConnect Planning Region for purposes of Order No. 1000:

Arizona Public Service Company
Black Hills Colorado Electric Utility Company, LP
Black Hills Power, Inc.
Cheyenne Light, Fuel, & Power Company
El Paso Electric Company
NV Energy, Inc. Operating Companies
Public Service Company of Colorado
Public Service Company of New Mexico
Tri-State Generation and Transmission Association, Inc.
Tucson Electric Power Company
UNS Electric, Inc.

3. WestConnect Objectives and Procedures for Regional Transmission Planning

The Regional Planning Process will produce a Regional Plan that complies with existing Order No. 890 principles:

Coordination

Openness

Transparency

Information exchange

Comparability

Dispute resolution

Tri-State, along with the other Planning Participation Agreement participants, shall work through the Regional Planning Process to integrate its transmission plan with the other WestConnect participant transmission plans into a single ten year Regional Plan for the WestConnect footprint by:

Actively coordinating development of the Regional Plan, including incorporating information, as appropriate, from all stakeholders;

Coordinating, developing and updating common base cases to be used for all study efforts within the Regional Planning Process and ensuring that each plan adheres to the methodology and format developed for the Regional Plan;

Providing funding for the Regional Planning Process and all planning management functions pursuant to the Planning Participation Agreement;

Maintaining a regional planning section at www.westconnect.com where all WestConnect planning information, including meeting notices, meeting minutes, reports, presentations, and other pertinent information is posted;

Posting detailed notices of all regional and local planning meeting agendas on the WestConnect website; and

Establishing a cost allocation process for regional transmission projects selected in the Regional Planning Process for cost allocation.

B. Roles in the Regional Planning Process

1. PMC Role

The PMC is responsible for bringing transmission planning information together and sharing updates on active projects. The PMC provides an open forum where any stakeholder interested in the planning of the regional transmission system in the WestConnect footprint can participate and obtain information regarding base cases, plans, and projects and provide input or express its needs as they relate to the transmission system. On a biennial basis and in coordination with its members, Transmission Owners, and other interested stakeholders, the PMC will develop the Regional Plan. The PMC, after considering the data and comments supplied by customers and other stakeholders, is to develop a regional transmission plan that treats similarly-situated customers (*e.g.*, network, retail network, and native load) comparably in transmission system planning.

The PMC is charged with development and approval of the Regional Plan. The PMC is structured to be comprised of representatives from each stakeholder sector. The PMC will be empowered to create and dissolve subcommittees as necessary to facilitate fulfillment of its responsibilities in developing the Regional Plan.

2. Stakeholder Participation and Assistance

Stakeholders may participate in the Regional Planning Process by any one or more of the following ways: (a) joining one of five WestConnect regional transmission planning membership sectors described below; (b) by attending publicly-posted WestConnect regional transmission planning stakeholder meetings; and/or (c) by submitting project proposals for consideration and evaluation in the Regional Planning Process.

Attendance at meetings is open to all interested stakeholders. These meetings will include discussion of models, study criteria and assumptions, and progress updates. Formal participation, including voting as allowed by the process, can be achieved through payment of applicable fees and annual dues in accordance with the Planning Participation Agreement. Transmission Owners with a Load Serving Obligation will not be responsible for annual dues because Transmission Owners with a Load Serving Obligation will be the default source of monies to support WestConnect activities beyond dues paid by other organizations.

WestConnect Planning Region members will assist stakeholders interested in becoming involved in the Regional Planning Process by directing them to appropriate contact persons and websites. (*See* at www.westconnect.com). All stakeholders are encouraged to bring their plans for future generators, loads or transmission services to the WestConnect planning meetings. Each transmission planning cycle will contain a period during which project ideas are accepted for potential inclusion in that cycle's Regional Plan.

3. Forum for Evaluation

The WestConnect Regional Planning Process also provides a forum for transmission project sponsors to introduce their specific projects to interested stakeholders and potential partners and allows for joint study of these projects by interested parties, coordination with other projects, and project participation, including ownership from other interested parties. This may include evaluation of transmission alternatives or non-transmission alternatives in coordination with the Regional Planning Process.

4. Stakeholder Meetings

WestConnect will hold open stakeholder meetings on at least a semi-annual basis, or as needed and noticed by the PMC with 30 days advance notice to update stakeholders about its progress in developing the Regional Plan and to solicit input regarding material matters of process related to the Regional Plan. Notice for such meetings will be posted on the WestConnect website and via email to the Regional Planning Process email distribution list.

The meeting agendas for all WestConnect planning meetings will be sufficiently detailed, posted on the WestConnect website, and circulated in advance of the meetings in order to allow stakeholders the ability to choose their meeting attendance most efficiently.

5. WestConnect Planning Process Governance

a. Membership Sectors

The Regional Planning Process will be governed by the PMC, which will be tasked with executing the Regional Planning Process and will have authority for approving the Regional Plan. For those entities desiring to be a part of the management of the Regional Planning Process, one of five PMC membership sectors is available:

Transmission Owners with Load Serving Obligations
Transmission Customers
Independent Transmission Developers and Owners
State Regulatory Commissions
Key Interest Groups

Only Transmission Owners that have load serving obligations individually or through their members may join the Transmission Owners with Load Serving Obligations membership sector. The Transmission Owners with Load Serving Obligations sector will be comprised of (a) those Transmission Owners that enroll in the WestConnect Planning Region for purposes of Order No. 1000; and (b) those Transmission Owners that elect to participate in the WestConnect Regional Planning Process as Coordinating Transmission Owners.

Except for Public Utilities that are required to comply with Order No. 1000, any entity may join any membership sector for which it qualifies, but may only participate in one membership sector at a time. If a non-public utility is qualified to join the Transmission Owners with Load Serving Obligations sector as well as one or more other sectors, and the non-public utility elects to join a sector other than the Transmission Owners with Load Serving Obligations sector, the PMC will not perform the function of regional transmission planning for that entity. Additionally, if a member of the Transmission Owner with Load Serving Obligations sector owns transmission facilities located in another planning region, the PMC will not perform the function of regional planning for such facilities located in another planning region.

b. Planning Management Committee

The PMC will be empowered to create and dissolve subcommittees as necessary to ensure timely fulfillment of its responsibilities; to assess fees for membership status on the PMC; and to assess fees for projects submitted for evaluation as part of the Regional Planning

Process. The PMC is to manage the Regional Planning Process, including approval of the Regional Plan that includes application of regional cost allocation methodologies.

The PMC is to coordinate and have the decision making authority over whether to accept recommendations from the Planning Subcommittee (PS) and Cost Allocation Subcommittee (CAS). The PMC, among other things, is to develop and approve the Regional Plan based on recommendations from the PS and CAS; and develop and approve a scope of work, work plan, and periodic reporting for WestConnect planning functions, including holding a minimum of two stakeholder informational meetings per year. The PMC is to appoint the chair of the PS and CAS. The chair for each subcommittee must be a representative of the Transmission Owners with Load Serving Obligations member sector.

The PS responsibilities include, but are not limited to, reviewing and making recommendations to the PMC for development of study plans, establishing base cases, evaluating potential solutions to regional transmission needs, producing and recommending the Regional Plan for PMC approval, and coordinating with the CAS. The PS is to provide public notice of committee meetings and provide opportunities for stakeholders to provide comments on the process and proposed plan.

The CAS responsibilities include, but are not limited to, performing and/or overseeing the performance of the cost allocation methodology. The CAS also is to review and make recommendations to the PMC for modifying definitions of benefits and cost allocation methodology as necessary to meet WestConnect planning principles on identification of beneficiaries and cost allocation. The CAS is to review and recommend projects to the PMC for purposes of cost allocation identified in the Regional Planning Process. The CAS is to provide public notice of committee meetings and provide opportunities for stakeholders to provide comments on the process and proposed cost allocation.

All actions of the PMC (including approval of the Regional Plan) will be made possible by satisfying either of the following requirements:

75% of the members voting of at least three (3) sectors approving a motion, where one of the three sectors approving is the Transmission Owners with Load Serving Obligation sector; or

75% of the members voting of the four member sectors other than the Transmission Owners with Load Serving Obligation sector approving a motion and two-thirds (2/3) of the members voting of the Transmission Owners with Load Serving Obligation sector approving a motion.

Each entity within a membership sector is entitled to one vote on items presented for decision.

Any closed executive sessions of the PMC will be to address matters outside of the development of the Regional Planning Process, including matters involving contracts, personnel, financial matters, or legal matters such as, but not limited to, litigation (whether active or threatened).

c. Submission of Data by Customers, Transmission Developers and Transmission Owners

When stakeholder feedback on modeling assumptions is requested, the data submittal period for such feedback will be established by the PMC. In all cases, requests for submittal of data from WestConnect members and stakeholders will be followed by a data submittal window lasting no less than thirty (30) days from the date of such requests. In addition, consistent with the Regional Planning Process, any interested stakeholder may submit project ideas for consideration in the Regional Plan without a need for that stakeholder to qualify for a project submittal for purposes of cost allocation. Specific project submittals are treated differently than generalized project ideas. For any project submittal seeking study by the PMC in the Regional Planning Process to address a regional need identified by the PMC (without regard to whether the project seeks cost allocation), a project submittal deposit will be collected and made subject to later true-up based upon the actual cost of the study(ies) performed. Project submittals are to be accepted through the fifth (5th) quarter of the planning cycle (or first (1st) quarter of the second (2nd) year), and are addressed in Section III.C.5 of this Attachment K. A timeline detailing the timing and notice for submission of information and input can be found in Exhibit 1 of this Attachment K.

1. Transmission Customers

Transmission customers shall generally submit their load forecast and other relevant data through the WestConnect member's (*e.g.*, Tri-State's) local transmission planning process. However, from time to time, there may be a need for transmission customers participating in the Regional Planning Process to submit data directly to WestConnect. This data may include, but is not limited to load forecasts, generation resource plans, demand side management resources, proposed transmission upgrade recommendations, and feedback regarding certain assumptions in the planning process.

No less than thirty (30) days' notice will be given for customers to submit any required data and data submissions will generally be able to be made via email or by posting information to a designated website.

2. Independent Transmission Developers and Owners

Transmission Developers are entities with project ideas they wish to submit into the Regional Planning Process. These may include project submittals that the developer wishes to be considered to address an identified regional need (whether or not the project is eligible for regional cost allocation).

Each regional transmission planning cycle will include a submission period for project ideas as described in Section III.C.5 below. Notice of the submission period will be posted on the WestConnect website and will also be made via email to WestConnect stakeholders. The submission period will last for no less than thirty (30) days and during this time, any entity that wishes to submit a transmission project for consideration in the Regional Planning Process to address an identified regional need may do so.

Projects proposed by Independent Transmission Developers and Owners are subject to the same Reliability Standards as projects submitted by Transmission Owners with Load Serving Obligations. The project developer shall register with NERC and WECC in accordance with the applicable registration rules in the NERC Rules of Procedure. In addition, project developers shall observe and comply with regional requirements as established by the applicable regional reliability organizations, and all local, state, regional, and federal requirements.

3. Merchant Transmission Developers

Merchant Transmission Developers are entities pursuing completion of projects that do not wish to have their projects considered for regional cost allocation. Nonetheless, coordination between merchant projects and the Regional Planning Process is necessary to effect a coordinated Regional Plan that considers all system needs.

Each regional transmission planning cycle will include a submission period for project submittals to address an identified regional need, as described in Section III.C.5 below. Notice of the submission period will be posted on the WestConnect website and will also be made via email to WestConnect stakeholders. In addition, it is necessary for merchant transmission developers to provide adequate information and data to allow the PMC to assess the potential reliability and operational impacts of the merchant transmission developer's proposed transmission facilities on other systems in the region. The submission period will last for no less than thirty (30) days and during this time sponsors of merchant transmission projects that are believed to impact the WestConnect transmission system will be asked to provide certain project information.

Projects proposed by Merchant Transmission Developers are subject to the same Reliability Standards as projects submitted by Transmission Owners with Load Serving Obligations. The project developer is responsible for properly registering with NERC and WECC in accordance with the applicable registration rules in the NERC Rules of Procedure. In addition, project developers shall observe and comply with regional requirements as established by the applicable regional reliability organization and all local, state, regional, and federal requirements.

4. Transmission Owners with Load Serving Obligations

Transmission Owners that are members of the WestConnect Planning Region are responsible for providing all necessary system information to the Regional Planning Process.

At the beginning of each regional transmission planning cycle, Transmission Owners that are participating in the Regional Planning Process shall be responsible for verifying the accuracy of any data (including, but not limited to system topology and project proposal information) they have previously submitted. Transmission Owners shall also be required to submit all relevant data for any new projects being proposed for inclusion in the Regional Plan to address an identified regional need in accordance with Section III.C.5 below. Transmission Owners shall also be responsible for submitting any project plans developed through their local transmission planning processes for inclusion in the Regional Plan models.

5. Transmission Project Submittals

All submittals of transmission projects to address an identified regional need, without regard to whether or not the project seeks regional cost allocation, are to contain the information set forth below, together with the identified deposit for study costs, and be submitted timely within the posted submittal period in order for the project submittal to be eligible for evaluation in the Regional Planning Process. A single project submittal may not seek multiple study requests. To the extent a project proponent seeks to have its project studied under a variety of alternative project assumptions, the individual alternatives must be submitted as individual project submittals. To be eligible to propose a project for selection in the Regional Plan, a project proponent must also be an active member in good standing within one of the five PMC membership sectors described above in Section III.B.5.a:

- Submitting entity contact information
- Explanation of how the project is a more efficient or cost-effective solution to regional transmission needs*
- A detailed project description including, but not limited to, the following:

  - Scope
  - Points of interconnection to existing (or planned) system
  - Operating Voltage and Alternating Current or Direct Current status
  - Circuit configuration (Single, Double, Double-Circuit capable, etc.)
  - Impedance information
  - Approximate circuit mileage
- Description of any special facilities (series capacitors, phase shifting transformers, etc.) required for the project
- Diagram showing geographical location and preferred route; general description of permitting challenges
- Estimated Project Cost and description of basis for that cost*
- Any independent study work of or relevant to the project
- Any WECC study work of or relevant to the project
- Status within the WECC path rating process
- The project in-service date
- Change files to add the project to a standard system power flow model
- Description of plan for post-construction maintenance and operation of the proposed line
- A $25,000 deposit to support the cost of relevant study work, subject to true-up (up or down) based upon the actual cost of the study(ies).* The true-up will include interest on the difference between the deposit and the actual cost, with such interest calculated in accordance with section 35.19a(a)(2) of FERC's regulations. A description of the costs to which the deposit was applied, how the costs were calculated, and an accounting of the costs will be provided to each project sponsor within 30 calendar days of the completion of the study. Dispute resolution is addressed pursuant to Section V.
- Comparison Risk Score from WECC Environmental Data Task Force, if available
- Impacts to other regions. The applicant must provide transmission system impacts studies showing system reliability impacts to neighboring transmission systems or another transmission planning region. The information should identify all costs associated with any required upgrades to mitigate adverse impacts on other transmission systems.*

If impact studies and costs are not available at the time of submittal, the project proponent may request that impact studies be performed, at the project proponent's expense, as part of the analysis to determine whether the project is the more efficient or cost-effective solution. Requests for transmission system impact studies are approved through the PMC depending on whether the project proponent provides funding for the analysis. The PMC will provide, subject to appropriate confidentiality and CEII restrictions, the information in the possession of the PMC that an applicant needs to perform the transmission system impact study and to identify the costs associated with any upgrades required to mitigate adverse impacts.

* Merchant transmission developers are exempt from these requirements.

There is to be an open submission period for project proposals to address identified regional needs. Notice of the submission period will be posted on the WestConnect website and will also be made via email to WestConnect stakeholders. The submission period will last for no less than thirty (30) days and will end by the fifth (5th) quarter of the WestConnect planning cycle (or first (1st) quarter of the second (2nd) year of the planning cycle). Proposals submitted outside that window will not be considered. The PMC will have the authority to determine the completeness of a project submittal. Project submittals deemed incomplete will be granted a reasonable opportunity to cure any deficiencies identified in writing by the PMC.

Any stakeholder wishing to present a project submittal to address an identified regional need shall be required to submit the data listed above for the project to be considered in the Regional Planning Process. Should the submitting stakeholder believe certain information is not necessary, it shall identify the information it believes is not necessary and shall provide a justification for its conclusion that the information is not necessary. The PMC retains the sole authority for determining completeness of the information submittal. After the completion of the project submittal period, the PMC will post a document on the WestConnect website detailing why any projects were rejected as incomplete. Upon posting of the document, any project submittal rejected as incomplete will be given a reasonable opportunity to cure the reason(s) it was rejected to the satisfaction of the PMC in its sole discretion.

6. Submission of Non-Transmission Alternative Projects

Any stakeholder may submit projects proposing non-transmission alternatives to address an identified regional need for evaluation under the Regional Planning Process. The submission period will last for no less than thirty (30) days. The submission window will end by the fifth (5th) quarter of the WestConnect planning cycle (or first (1st) quarter of the second (2nd) year of the planning cycle). The following criteria must be satisfied in order for a non-transmission alternative project submittal to be evaluated under the Regional Planning Process:

- Basic description of the project (fuel, size, location, point of contact)
- Operational benefits
- Load offset, if applicable
- Description of the issue sought to be resolved by the generating facility or non-transmission alternative, including reference to any results of prior technical studies
- Network model of the project flow study
- Short-circuit data
- Protection data
- Other technical data that might be needed for resources
- Project construction and operating costs
- Additional miscellaneous data (e.g., change files if available)

As with entities submitting a transmission project under Section III.C.5, those who submit under Section III.C.6 a non-transmission alternative under the Regional Planning Process must adhere to and provide the same or equivalent information (and deposit for study costs) as transmission alternatives, as described in Section III.C.5, above. Should the submitting stakeholder believe certain information is not necessary, it shall identify the information it believes is not necessary and shall provide a justification for its conclusion that the information is not necessary. Although non-transmission alternative projects will be considered in the Regional Planning Process, they are not eligible for regional cost allocation.

7. The WestConnect Regional Planning Cycle

The WestConnect regional transmission planning cycle is biennial. The WestConnect PMC will develop and publish a Regional Plan every other year.

D. Transmission Developer Qualification Criteria

1. In General

A transmission developer that seeks to be eligible to use the regional cost allocation methodology for a transmission project selected in the Regional Plan for purposes of cost allocation must identify its technical and financial capabilities to develop, construct, own, and operate a proposed transmission project. To be clear, satisfaction of the criteria set forth below does not confer upon the transmission developer any right to:

(i) construct, own, and/or operate a transmission project,
(ii) collect the costs associated with the construction, ownership and/or operation of a transmission project,
(iii) provide transmission services on the transmission facilities constructed, owned and/or operated.

The applicable governing governmental authorities are the only entities empowered to confer any such rights to a transmission developer. The PMC is not a governmental authority.

2. Information Submittal

A transmission developer seeking eligibility for potential designation as the entity eligible to use the regional cost allocation for a transmission project selected in the Regional Plan for purposes of cost allocation must submit to the PMC the following information during the first quarter of the WestConnect planning cycle, except that during the first WestConnect planning cycle the PMC shall have the discretion to extend the period for the submission of this information:

a. Overview

A brief history and overview of the applicant demonstrating that the applicant has the capabilities to finance, own, construct, operate and maintain a regional transmission project consistent with Good Utility Practice within the state(s) within the WestConnect Planning Region. The applicant should identify all transmission projects it has constructed, owned, operated and/or maintained, and the states in which such projects are located.

b. Business Practices

A description of the applicant's experience in processes, procedures, and any historical performance related to engineering, constructing, operating and maintaining electric transmission facilities, and managing teams performing such activities. A discussion of the types of resources, including relevant capability and experience (in-house labor, contractors, other transmission providers, etc.) contemplated for the licensing, design, engineering, material and equipment procurement, siting and routing, Right-of-Way (ROW) and land acquisition, construction and project management related to the construction of transmission projects. The applicant should provide information related to any current or previous experience financing, owning, constructing, operating and maintaining and scheduling access to regional transmission facilities.

c. Compliance History

The applicant should provide an explanation of any violation(s) of NERC and/or Regional Entity Reliability Standards and/or other regulatory requirements pertaining to the development, construction, ownership, operation, and/or maintenance of electric transmission facilities by the applicant or any parent, owner, affiliate, or member of the applicant that is an Alternate Qualifying Entity under Section III.D.2.l. Notwithstanding the foregoing, if at the time the applicant submits the information required by this Section III.D.2, the applicant has not developed, constructed, owned, operated or maintained electric transmission facilities, the applicant shall instead submit such information for any electric distribution or generating facilities it develops, constructs owns, operates and/or maintains, as applicable, to demonstrate its compliance history.

d. Participation in the Regional Planning Process

A discussion of the applicant's participation within the Regional Planning Process or any other planning forums for the identification, analysis, and communication of transmission projects.

e. Project Execution

A discussion of the capability and experience that would enable the applicant to comply with all on-going scheduling, operating, and maintenance activities associated with project development and execution.

f. Right-of-Way Acquisition Ability

The applicant's preexisting procedures and historical practices for siting, permitting, landowner relations, and routing transmission projects including, acquiring ROW and land, and managing ROW and land acquisition for transmission facilities. Any process or procedures that address siting or routing transmission facilities through environmentally sensitive areas and mitigation thereof. If the entity does not have such preexisting procedures, it shall provide a detailed description of its plan for acquiring ROW and land and managing ROW and land acquisition.

g. Financial Health

The applicant must demonstrate creditworthiness and adequate capital resources to finance transmission projects. The applicant shall either have an investment grade credit rating from both S&P and Moody's or provide corporate financial statements for the most recent five years for which they are available. Entities that do not have a credit rating, or entities less than five years old, shall provide corporate financial statements for each year that is available. Alternatively, the applicant may provide a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to the PMC.

The following ratios must be provided with any explanations regarding the ratios:

Funds from operations-to-interest coverage.
Funds from operation-to-total debt.
Total debt-to-total capital.

The applicant must indicate the levels of the above ratios the company will maintain during and following construction of the transmission element.

The PMC may request additional information or clarification as necessary.

h. Safety Program

The applicant must demonstrate that it has an adequate internal safety program, contractor safety program, safety performance record and program execution.

i. Transmission Operations

The applicant must: demonstrate that it has the ability to undertake control center operations capabilities, including reservations, scheduling, and outage coordination; demonstrate that it has the ability to obtain required path ratings; provide evidence of its NERC compliance process and compliance history, as applicable; demonstrate any existing required NERC certifications or the ability to obtain any applicable NERC certifications; establish required Total Transfer Capability; provide evidence of storm/outage response and restoration plans; provide evidence of its record of past reliability performance, as applicable; and provide a statement of which entity will be operating completed transmission facilities and will be responsible for staffing, equipment, and crew training. A potential transmission developer will not be required to have an operations entity under contract at the time it seeks to be eligible to use the regional cost allocation method for a transmission project selected in the Regional Plan for purposes of cost allocation.

j. Transmission Maintenance

The applicant must demonstrate that it has, or has plans to develop, an adequate transmission maintenance program, including staffing and crew training, transmission facility and equipment maintenance, record of past maintenance performance, NERC compliance process and any past history of NERC compliance or plans to develop a NERC compliance program, and provide a statement of which entity will be performing maintenance on completed transmission facilities. A potential transmission developer will not be required to have a maintenance entity under contract at the time it seeks to be eligible to use the regional cost allocation method for a transmission project selected in the Regional Plan for purposes of cost allocation.

k. Regulatory Compliance

The applicant must demonstrate the ability, or plans to develop the ability, to comply with Good Utility Practice, WECC criteria and regional Reliability Standards, NERC Reliability Standards, construction standards, industry standards, and environmental standards.

l. Affiliation Agreements

A transmission developer can demonstrate that it meets these criteria either on its own or by relying on an entity or entities with whom it has a corporate affiliation or other third parties with relevant experience (Alternate Qualifying Entity(ies)). In lieu of a contractual or affiliate relationship with one or more Alternate Qualifying Entity(ies) and to the extent a transmission developer intends to rely upon third parties for meeting those criteria, the transmission developer must provide in attestation form, an identification of its preferred third-party contractor(s) and indicate when it plans to enter into a definitive agreement with its third-party contractor(s). If the transmission developer seeks to satisfy the criteria in whole or in part by relying on one or more Alternate Qualifying Entity(ies), the transmission developer must submit: (1) materials demonstrating to the PMC's satisfaction that the Alternate Qualifying Entity(ies) meet(s) the criteria for which the transmission developer is relying upon the alternate qualifying entity(ies) to satisfy; and (2) a commitment to provide in any project cost allocation application an executed agreement that contractually obligates the Alternate Qualifying Entity(ies) to perform the function(s) for which the transmission developer is relying upon the Alternate Qualifying Entity(ies) to satisfy.

m. WestConnect Membership

A transmission developer must be a member of either the WestConnect Transmission Owners with Load Serving Obligations or Independent Transmission Developers and Owners sector, or must agree to join the WestConnect Transmission Owners with Load Serving Obligations or Independent Transmission Developers and Owners sector and agreed to sign the Planning Participation Agreement if the transmission developer seeks to be an entity eligible to use the regional cost allocation method for a transmission project selected in the Regional Plan for purposes of cost allocation.

n. Other

Any other relevant project development experience that the transmission developer believes may demonstrate its expertise in the above areas.

3. Identification of Transmission Developers Satisfying the Criteria

a. Notification to Transmission Developer

No later than September 30 each year, the PMC is to notify each transmission developer whether it has satisfied the stated criteria. A transmission developer failing to satisfy one or more of the qualification criteria is to be informed of the failure(s) and accorded an additional opportunity to cure any deficiency(ies) within thirty (30) calendar days of notice from the PMC by providing any additional information.

The PMC is to inform the transmission developer whether the additional information satisfies the qualification criteria within forty-five (45) calendar days of receipt of the additional information.

The PMC is to identify the transmission developers that have satisfied the qualification criteria (the “Eligible Transmission Developers”) by posting on the WestConnect website, on or before December 31 of each year.

b. Annual Recertification Process and Reporting Requirements

By June 30 of each year, each Eligible Transmission Developer must submit to WestConnect a notarized letter signed by an authorized officer of the Eligible Transmission Developer certifying that the Eligible Transmission Developer continues to meet the current qualification criteria.

The Eligible Transmission Developer shall submit to the PMC an annual certification fee equal to the amount of the WestConnect annual membership fee. If the Eligible Transmission Developer is a member of WestConnect and is current in payment of its annual membership fee, then no certification fee will be required.

If at any time there is a change to the information provided in its application, an Eligible Transmission Developer shall be required to inform the PMC chair within thirty (30) calendar days of such change so that the PMC may determine whether the Eligible Transmission Developer continues to satisfy the qualification criteria. Upon notification of any such change, the PMC shall have the option to: (1) determine that the change does not affect the status of the transmission developer as an Eligible Transmission Developer; (2) suspend the transmission developer's eligibility status until any deficiency in the transmission developer's qualifications is cured; (3) allow the transmission developer to maintain its eligibility status for a limited time period, as specified by the PMC, while the transmission developer cures the deficiency; or (4) terminate the transmission developer's eligibility status.

c. Termination of Eligibility Status

The PMC may terminate an Eligible Transmission Developer's status if the Eligible Transmission Developer: (1) fails to submit its annual certification letter; (2) fails to pay the applicable WestConnect membership fees; (3) experiences a change in its qualifications and the PMC determines that it may no longer qualify as an Eligible Transmission Developer; (4) informs the PMC that it no longer desires to be an Eligible Transmission Developer; (5) fails to notify the PMC of a change to the information provided in its application within thirty (30) days of such change; or (6) fails to execute the Planning Participation Agreement as agreed to in the qualification criteria within a reasonable time defined by the PMC, after seeking to be an entity eligible to use the regional cost allocation method for a transmission project selected in the Regional Plan for purposes of cost allocation.

E. Overview of Regional Planning Methodology and Evaluation Process

The Regional Planning Process is intended to identify regional needs and more efficient or cost-effective solutions to satisfy those needs. Consistent with Order No. 890, qualified projects timely submitted through the Regional Planning Process will be evaluated and selected from competing solutions and resources such that all types of resources, as described below, are considered on a comparable basis. The same criteria and evaluation process will be applied to competing solutions and/or projects, regardless of type or class of stakeholder proposing them. Where a regional transmission need is identified, the PMC is to perform studies that seek to meet that need through regional projects, even in the absence of project proposals advanced by stakeholders or projects identified through the WECC process. When the PMC performs a study to meet an identified regional need in circumstances where no stakeholder has submitted a project proposal to meet that regional need, the PMC is to pursue such studies in a not unduly discriminatory fashion. The study methods employed for PMC-initiated studies will be the same types of study methods employed for stakeholder-initiated studies (see, e.g., Section III.F addressing the use of NERC Transmission Planning (TPL) Reliability Standards for regional reliability projects, Section III.G addressing the use of production cost modeling for regional economic projects, and Section III.H addressing the identification of Public Policy Requirements for regional public policy-driven projects).

The solution alternatives will be evaluated against one another on the basis of the following criteria to select the preferred solution or combination of solutions: (1) ability to fulfill the identified need practically; (2) ability to meet applicable reliability criteria or NERC Transmission Planning Standards issues; (3) technical, operational and financial feasibility; (4) operational benefits/constraints or issues; (5) cost-effectiveness over the time frame of the study or the life of the facilities, as appropriate (including adjustments, as necessary, for operational benefits/constraints or issues, including dependability); (6) where applicable, consistency with Public Policy Requirements or regulatory requirements, including cost recovery through regulated rates; and (7) a project must be determined by the PMC to be a more efficient or cost-effective solution to one or more regional transmission needs to be eligible for regional cost allocation, as more particularly described below.

The Regional Planning Process provides for an assessment of regional solutions falling in one or more of the following categories:

Regional reliability solutions
Regional economic solutions
Regional transmission needs driven by Public Policy Requirements

Non-transmission alternatives

Tri-State encourages all interested stakeholders to consult the Business Practice Manual for additional details regarding the planning process, timing, and implementation mechanics.

All WestConnect Transmission Owners with Load Serving Obligation shall be responsible for submitting their local transmission plans for inclusion in the Regional Plan in accordance with the timeline stated in the Business Practice Manual. Those individual plans will be included in the Regional Plan base case system models.

F. WestConnect Reliability Planning Process

Once the base case is established and verified, the PMC is to perform a regional reliability assessment in which the base case system models will then be checked for adherence to the relevant NERC or WECC Transmission Planning Reliability Standards, through appropriate studies, including, but not limited to, steady-state power flow, voltage, stability, short circuit, and transient studies as outlined in the Business Practice Manual. If a reliability violation is identified in this power flow process, the violation will be referred back to the appropriate Transmission Owner.

The PMC will identify projects to resolve any regional violations that impact more than one Transmission Owner of relevant NERC or WECC Transmission Planning Reliability Standards or WECC criteria. In addition, an opportunity will be afforded to any interested party to propose regional reliability projects that are more efficient or cost-effective than other proposed solutions. The PMC will then identify the more efficient or cost-effective regional transmission project that meets the identified regional transmission need, taking into account factors such as how long the project would take to complete and the timing of the need. Because local Transmission Owners are ultimately responsible for compliance with NERC Reliability Standards and for meeting local needs the local transmission plans will not be modified, however, the PMC may identify more efficient or cost-effective regional transmission projects. As seen in Exhibit 1 of this Attachment K, the PMC will perform the regional reliability assessment and, if necessary, identify a regional need for transmission projects to resolve any violations that impact more than one Transmission Owner in the fourth quarter of the planning cycle.

G. WestConnect Economic Planning Process

As part of the Regional Planning Process, the PMC is to analyze whether there are projects that have the potential to reduce the total delivered cost of energy by alleviating congestion or providing other economic benefits to the WestConnect Planning Region through production cost modeling. This analysis also utilizes WECC Board-approved recommendations to further investigate congestion within the WestConnect Planning Region for congestion relief or economic benefits that has subsequently been validated by WestConnect. Additional projects may also be proposed by WestConnect stakeholders or developed through the stakeholder process for evaluation of economic benefits. Under the Regional Planning Process, the PMC will identify more efficient or cost-effective regional transmission projects, but will not modify local transmission plans.

The WestConnect economic planning process will analyze benefits via detailed production cost simulations. The models employed in the production cost simulations will appropriately consider the impact of transmission projects on production cost and system congestion. The WestConnect economic planning process will also consider the value of decreased reserve sharing requirements in its development of a plan that is more efficient or cost-effective. As seen in Exhibit 1 of this Attachment K, the PMC will develop the production cost modeling analysis in the second (2nd) and third (3rd) quarters of the planning cycle and identify economic transmission projects in the sixth (6th) quarter and parts of the fifth (5th) and seventh (7th) quarters of the planning cycle.

H. WestConnect Public Policy Planning Process

1. Procedures for Identifying Transmission Needs Driven by Public Policy Requirements

It is anticipated that any regional transmission need that is driven by Public Policy Requirements will be addressed initially within the local planning cycles of the individual Transmission Owners in the WestConnect Planning Region through the consideration of local transmission needs driven by a Public Policy Requirement, since a Public Policy Requirement is a requirement that is imposed upon individual Transmission Owners (as opposed to a requirement that is imposed on a geographic region). For those Public Policy Requirements that affect more than one Transmission Owner in the WestConnect Planning Region, a solution identified at the local level to satisfy the local needs of the affected Transmission Owner(s), may also satisfy a regional transmission need identified by the PMC for the WestConnect Planning Region.

WestConnect Transmission Owner members that are planning consistent with Order No. 890 will continue to conduct local transmission planning processes (Section II.E of this Attachment K), which provide a forum for discussions on local transmission needs driven by Public Policy Requirements. These local processes provide the basis for the individual Transmission Owners' local transmission plans, which are then incorporated into the regional base case at the start of the Regional Planning Process under Order No. 1000.

The PMC is to provide notice on the WestConnect website of both regional transmission planning meetings convened by the PMC for the WestConnect region, and local transmission planning meetings of the individual Transmission Owners in the WestConnect region.

The PMC will begin the evaluation of regional transmission needs driven by Public Policy Requirements by identifying any Public Policy Requirements that are driving local transmission needs of the Transmission Owners in the WestConnect Planning Region, and including them in the transmission system models (the regional base case) underlying the development of the Regional Plan. Then, the PMC will seek the input of stakeholders in the WestConnect region on those Public Policy Requirements in an effort to engage stakeholders in the process of identifying regional transmission needs driven by Public Policy Requirements. The PMC will communicate with stakeholders through public postings on the WestConnect website of meeting announcements and discussion forums. In addition, the PMC is to establish an email distribution list for those stakeholders who indicate a desire to receive information via electronic list serves.

After allowing for stakeholder input on regional transmission needs driven by Public Policy Requirements and regional solutions to those needs, as part of the Regional Planning Process, the PMC is to identify in the Regional Plan those regional transmission needs driven by Public Policy Requirements that were selected by the PMC for evaluation of regional solutions.

In selecting those regional transmission needs driven by Public Policy Requirements that will be evaluated for regional solutions in the current planning cycle, the PMC is to consider, on a non-discriminatory basis, factors, including but not limited to, the following:

whether the Public Policy Requirement is driving a regional transmission need that can be reasonably identified in the current planning cycle;

the feasibility of addressing the regional transmission need driven by the Public Policy Requirement in the current planning cycle;

the factual basis supporting the regional transmission need driven by the Public Policy Requirement; and

whether a Public Policy Requirement has been identified for which a regional transmission need has not yet materialized, or for which there may exist a regional transmission need but the development of a solution to that need is premature.

No single factor shall necessarily be determinative in selecting among the potential regional transmission needs driven by Public Policy Requirements.

The process by which the PMC is to identify those regional transmission needs for which a regional transmission solution(s) will be evaluated, out of what may be a larger set of regional transmission needs, is to utilize the communication channels it has in place with stakeholders, identified above (open meetings and discussion forums convened by the PMC), through which regional transmission needs driven by Public Policy Requirements are to be part of the open dialogue.

2. Procedures for Identifying Solutions to Regional Transmission Needs Driven by Public Policy Requirements

Stakeholders are to have opportunities to participate in discussions during the Regional Planning Process with respect to the development of solutions to regional transmission needs driven by Public Policy Requirements. Such participation may take the form of attending planning meetings, offering comments for consideration by the PMC on solutions to regional needs driven by Public Policy Requirements, and offering comments on proposals made by other stakeholders or by the PMC. Stakeholders that are members of the WestConnect PMC are performing the function of regional transmission planning and developing regional solutions to identified regional transmission needs driven by Public Policy Requirements through membership on subcommittees of the PMC.

After allowing for stakeholder input on solutions to regional transmission needs driven by Public Policy Requirements, as part of the Regional Planning Process, the PMC is to identify in the Regional Plan those regional transmission solutions driven by Public Policy Requirements that were selected by the PMC and any regional transmission project(s) that more efficiently or cost-effectively meet those needs.

The procedures for identifying and evaluating potential solutions to the identified transmission needs driven by Public Policy Requirements are the same as those procedures used to evaluate any other project proposed in the Regional Planning Process, whether or not submitted for purposes of cost allocation.

The PMC will perform a Public Policy Requirements analysis to help identify if a transmission solution is necessary to meet an enacted public policy. For a transmission need driven by Public Policy Requirements, the PMC will identify if a more efficient or cost-effective regional transmission solution exists based upon several different considerations, including consideration of whether the project is necessary and capable of meeting transmission needs driven by Public Policy Requirements, while also

Efficiently resolving any criteria violations identified by studies pursuant to any relevant NERC Transmission Planning (TPL) Reliability Standards for regional reliability projects or WECC Transmission Planning Reliability Standards or WECC criteria, as applicable, that could impact more than one Transmission Owner as a result of a Public Policy Requirement or,

Producing economic benefits shown through detailed production cost simulations. The models employed in the production cost simulations will appropriately consider the impact of transmission projects on production cost, system congestion and the value of decreased reserve sharing requirements.

The PMC will develop the public policy analysis in the sixth (6th) quarter and parts of the fifth (5^{th}) and seventh (7^{th}) quarters of the planning cycle.

3. Proposed Public Policy

A public policy that is proposed, but not required (because it is not yet enacted or promulgated by the applicable governmental authority) may be considered through Section III.G (WestConnect Economic Planning Process) of this Attachment K, if time and resources permit.

4. Posting of Public Policy Needs

WestConnect will maintain on its website (i) a list of all transmission needs identified that are driven by Public Policy Requirements and that are included in the studies for the current regional transmission planning cycle; and (ii) an explanation of why other suggested transmission needs driven by Public Policy Requirements will not be evaluated.

I. Consideration of Non-Transmission Alternatives

Non-transmission alternatives submitted in accordance with Section III.C.6 above will be evaluated to determine if they will provide a more efficient or cost-effective solution to an identified regional transmission need. Non-transmission alternatives include, without limitation, technologies that defer or possibly eliminate the need for new and/or upgraded transmission lines, such as distributed generation resources, demand-side management (load management, such as energy efficiency and demand response programs), energy storage facilities and smart grid equipment that can help eliminate or mitigate a grid reliability problem, reduce uneconomic grid congestion, and/or help to meet grid needs driven by Public Policy Requirements. Non-transmission alternatives are not eligible for regional cost allocation.

J. Approval of the WestConnect Regional Plan

The Cost Allocation Subcommittee is to submit, for review and comment, the results of its project benefit/cost analysis and beneficiary determination to the PMC Chair and to the identified beneficiaries of the transmission projects proposed for cost allocation. The PMC shall make available to its Members sufficient information to allow for a reasonable opportunity to comment on the proposed selection. The PMC shall not make a determination on the project benefit/cost analysis and beneficiary determination until it has reviewed all comments. Upon approval of the PMC, the project benefit/cost analysis and beneficiary identifications shall be posted by the PMC on the WestConnect website.

1. CTO Acceptance of Cost Allocation

(i) Each coordinating transmission owner (CTO) beneficiary will indicate whether it accepts the cost allocation for the project, as follows:

1. A CTO Member, in its sole discretion, may elect to accept a cost allocation for each separate transmission facility for which it is identified as a beneficiary, but only if it notifies the Chair of the PMC in writing of its decision to accept any such cost allocation within sixty (60) calendar days after the benefit/cost analysis is posted by the PMC under this Section III.J; provided, however, that the PMC has the discretion to extend the 60-day period when additional time is necessary for an identified beneficiary to complete its internal review and deliberation process before deciding to accept the cost allocation.

2. A CTO Member giving notice that it elects to accept a cost allocation for a transmission facility may rescind that notice at any time prior to the end of the sixty (60) day period, or such extended period established in this Section III.J.1.

3. A CTO Member that does not accept a cost allocation for a transmission facility will not be subject to cost allocation for that transmission facility.

The information made available under this Section III.J will be electronically masked and made available pursuant to a process that the PMC reasonably determines is necessary to prevent the disclosure of confidential information or CEII contained in the information.

2. Recalculation of Benefits and Costs for Reliability Projects

The Cost Allocation Subcommittee will adjust, as necessary, its project benefit/cost analysis and beneficiary identification for any transmission project that continues to meet the region's criteria for regional cost allocation. For any CTO beneficiary that does not accept cost allocation for a project under this Section III.J, such CTO's transmission need(s) which was included within the identification of the region's transmission needs under Sections III.F through III.H (for which the regional project would have avoided an alternative reliability project in such CTO's local transmission plan) will be removed as a regional transmission need for purposes of justifying a project's approval as a project eligible for inclusion in the Regional Plan for purposes of cost allocation.

3. Recalculation of Benefits and Costs for Public Policy Requirements Projects

The Cost Allocation Subcommittee will adjust, as necessary, its project benefit/cost analysis and beneficiary identification for any transmission project that continues to meet the region's criteria for regional cost allocation. For any CTO beneficiary that does not accept cost allocation for a project under this Section III.J, such CTO's transmission need(s) which was included within the identification of the region's transmission needs under Sections III.F through III.H (for which the regional project would have avoided an alternative Public Policy Requirements project in such CTO's local transmission plan) will be removed as a regional transmission need for purposes of justifying a project's approval as a project eligible for inclusion in the Regional Plan for purposes of cost allocation. This shall include any such CTO's resource needs necessary to comply with Public Policy Requirements.

4. Recalculation of Benefits and Costs for Economic Projects

The Cost Allocation Subcommittee will adjust, as necessary, its project benefit/cost analysis and beneficiary identification for any transmission project that continues to meet the region's criteria for regional cost allocation. For any CTO beneficiary that does not accept cost allocation for a project under this Section III.J, such CTO's transmission benefits which were included within the identification of the regional project's economic benefits under Sections III.F through III.H will be removed as a regional transmission benefit for purposes of justifying a project's approval as a project eligible for inclusion in the Regional Plan for purposes of cost allocation. This shall include the value of any economic benefits determined through the regional transmission plan to accrue to such CTO.

5. Resultant Increase in Beneficiary Cost Allocation

Any regional transmission project that continues to meet the region's benefit/cost and other criteria for regional cost allocation will remain eligible for selection in the Regional Plan for purposes of cost allocation.

6. Approval of the WestConnect Regional Transmission Plan

Upon completion of the process outlined above, the PMC will vote on whether to accept the proposed plan. The Regional Plan will document why projects were either included or not included in the Regional Plan. In addition, the Regional Plan is to describe the manner in which the applicable regional cost allocation methodology was applied to each project selected in the Regional Plan for purposes of regional cost allocation. Projects that meet system needs are incorporated into the Regional Plan. Participant funded projects and other types of projects may be included in the Regional Plan; however, those projects are not eligible for regional cost allocation.

K. Reevaluation of the WestConnect Regional Plan

The PMC is the governing body responsible for deciding whether to reevaluate the Regional Plan to determine if the conditions, facts and/or circumstances relied upon in initially selecting a transmission project for inclusion in the Regional Plan for purposes of cost allocation have changed and, as a result, require reevaluation. Reevaluation will begin within the second planning cycle following December 11, 2014, which is the effective date of the Planning Participation Agreement. The Regional Plan and any project selected for cost allocation in the Regional Plan, including any local or single-system transmission projects or planned transmission system upgrades to existing facilities selected for purposes of cost allocation, shall be subject to reevaluation in each subsequent planning cycle according to the criteria below. Upon reevaluation, the Regional Plan and any projects selected for purposes of cost allocation in connection therewith may be subject to modification, including the status as a project selected for cost allocation, with any costs reallocated under Section VI as if it were a new project. Only the PMC has the authority to modify the status of a transmission project selected for cost allocation. Conditions that trigger reevaluation are:

- The underlying project characteristics and/or regional or interregional needs change in the Regional Plan. Examples include, but are not limited to: (a) a project's failure to secure a developer, or a developer's failure to maintain the qualifications necessary to utilize regional cost allocation, or (b) a change (increase or decrease) in the identified beneficiaries of a project (which changes may occur through company acquisitions, dissolutions, or otherwise), (c) a change in the status of a large load that contributes to the need for a project, or (d) projects affected by a change in law or regulation;

- Projects that are delayed and fail to meet their submitted in-service date by more than two (2) years. This includes projects delayed by funding, regulatory approval, contractual administration, legal proceedings (including arbitration), construction delays, or other delays;

- Projects with significant project changes, including, but not limited to kilovolt (kV), megavolt ampere (MVA), or path rating, number of circuits, number of transmission elements, or interconnection locations; and

- Projects with a change in the calculation of benefits or benefit/cost (B/C) ratio that may affect whether the project selected for inclusion in the Regional Plan for purposes of cost allocation is a more efficient or cost-effective regional solution.

- Example 1: Where an increase in the selected project's costs, including but not limited to, material, labor, environmental mitigation, land acquisition, operations and maintenance, and mitigation for identified transmission system and region, causes the total project costs to increase above the level upon which the project was initially selected for inclusion in the Regional Plan for purposes of cost allocation, the inclusion of the regional project in the Regional Plan will be reevaluated to determine if the regional project continues to satisfy the region's B/C ratio and can be found to be a more efficient or cost-effective solution under current cost information.

- Example 2: A selected project's benefits may include identification of a reliability benefit in the form of remedying a violation of a Reliability Standard. If the identified beneficiary implements improvements, such as a Remedial Action Scheme, to achieve reliability in compliance with the Reliability Standard at issue, inclusion of the regional project in the regional plan will be reevaluated to determine if the regional project continues to satisfy the region's B/C ratio and can be found to be a more efficient or cost-effective solution under current benefit information.

- Example 3: Where a project's estimated benefits include benefits in the form of avoided costs (e.g., a regional project's ability to avoid a local project), and the project is not avoided, the inclusion of the regional project in the Regional Plan will be reevaluated to determine if the regional project continues to satisfy the region's B/C ratio and can be found to be a more efficient or cost-effective solution under current facts and circumstances.

Projects selected for purposes of cost allocation will continue to be reevaluated until all the following conditions have been met:

State and federal approval processes completed and approved (including cost recovery approval under Section 205 of the Federal Power Act as applicable);

All local, state, and federal siting permits have been approved; and

Major construction contracts have been issued.

When the Regional Plan is reevaluated as a result of any of the conditions triggering reevaluation addressed above, the PMC is to determine if an evaluation of alternative transmission solutions is needed in order to meet an identified regional need. In doing so, the PMC is to use the same processes and procedures it used in the identification of the original transmission solution to the regional need. If an alternative transmission solution is needed, the incumbent Transmission Owner may propose one or more solutions that it would implement within its retail distribution service territory or footprint, and if such proposed solution is a transmission facility, the Transmission Owner may submit the project for possible selection in the Regional Plan for purposes of cost allocation.

Projects not subject to reevaluation include, but are not limited to, the following:

Local or single system transmission projects that have been identified in individual Transmission Owner's Transmission Planning (TPL) Reliability Standards compliance assessments to mitigate reliability issues and that have not been proposed for (and selected by the PMC for) regional cost allocation; and

Planned transmission system upgrades to existing facilities that have not been proposed for (and selected by the PMC for) regional cost allocation.

Projects meeting any of the following criteria as of December 11, 2014 will also not be subject to reevaluation under the Regional Planning Process:

Projects of Transmission Owners who have signed the Planning Participation Agreement and that have received approval through local or state regulatory authorities or board approval;

Local or single system transmission projects that have been planned and submitted for inclusion in the Regional Plan or exist in the 10-year corporate capital project budgets; and

Projects that are undergoing review through the WECC Project Coordination and Rating Review Process as of December 11, 2014.

L. Confidential or Proprietary Information

Although the Regional Planning Process is open to all stakeholders, Stakeholders will be required to comply at all times with certain applicable confidentiality measures necessary to protect confidential information, proprietary information or CEII. From time to time the regional transmission planning studies and/or open stakeholder meetings may include access to base case data that are WECC proprietary data, information classified as CEII, or other similar confidential or proprietary information. In such cases, access to such confidential or proprietary information shall be limited to only those stakeholders that (i) hold membership in or execute a non-disclosure agreement (NDA) with WECC (See www.wecc.biz) or (ii) execute a non-disclosure agreement with the applicable WestConnect Planning Region members, as may be applicable.

Any entity wishing to access confidential information, subject to applicable Standards of Conduct requirements, discussed in the Regional Planning Process must execute an NDA, and submit it to mailto:NDA@westconnect.com.

IV. Coordination at the Western Interconnection Level

A. Tri-State – WestConnect Coordination

Tri-State shall coordinate its plan on a regional basis through WestConnect. WestConnect will coordinate its Regional Plan withWECC.

B. Procedures for Interregional Planning Project Review

1. WECC Coordination of Reliability Planning

WECC develops the Western Interconnection-wide databases for transmission planning analysis such as power flow, stability and dynamic voltage stability studies. The WECC-approved base cases are used for study purposes by transmission planners, regional transmission planning groups, and other entities that have signed non-disclosure agreements with WECC.

WECC maintains a database for reporting the status of all planned projects throughout the Western Interconnection.

WECC provides for coordination of planned projects through its Procedures for Regional Planning project review.

WECC's path rating process ensures that a new project will have no adverse effect on existing projects.

2. WECC-WECC Open Stakeholder Meetings

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

3. Role of WECC

WECC provides two main functions in relation to the WestConnect Regional Planning Process:

a. Development and Maintenance of the West-Wide Economic Planning Study Database.

WECC uses publicly available data to compile a database that can be used by a number of economic congestion study tools.

WECC's database is available for use in running economic congestion studies. For an interested stakeholder to utilize WECC's PROMOD planning model, it must comply with

WECC confidentiality requirements.

b. Performance of Economic Planning Studies

WECC has hierarchy of subcommittees and work groups which it will update databases, develop and approve a study plan that includes studying transmission customer high priority economic planning study requests as determined by the open WECC stakeholder process, perform the approved studies and document the results in a report.

c. Identification of Congested Paths for WestConnect Economic Review

Through WECC's economic study process, congested paths may be reviewed and identified as being candidates for economic transmission studies. Upon WECC Board approval of a designation for such a path and WestConnect validation, the Regional Planning Process will review the path for potential economic transmission solutions.

V. Dispute Resolution

In the event of a dispute concerning either a procedural or substantive matter within the jurisdiction of FERC, the following dispute resolution processes will apply:

A. WECC

If the dispute is one that is within the scope of the WECC dispute resolution procedures, then such procedures contained in the WECC Business and Governance Guidelines and Policies will apply. (See www.wecc.biz.)

B. Non-WECC Disputes

For disputes not within the scope of the WECC dispute resolution procedures, and for disputes not between or among the members of the PMC (which disputes will be subject to the dispute resolution provisions set forth in Section V.D), the dispute resolution procedures set forth in Section 12 of the Tri-State OATT will apply, with the added provision that upon agreement of the parties, any dispute that is not resolved by direct negotiation between or among the affected arbitration), and all applicable timelines will be suspended until such time as the mediation process terminates (unless otherwise agreed by the parties). Notwithstanding that the dispute resolution procedures under Section 12 of the Tri-State OATT apply only to Tri-State and its Transmission Customers, Section 12 of the Tri-State OATT will be deemed to be applicable to stakeholders for purposes of this Attachment K, except as otherwise provided herein.

C. Resolution by FERC

Notwithstanding anything to the contrary in this Section V, any affected party may refer either a procedural or substantive matter within the jurisdiction of FERC to FERC for resolution, for example, by filing with FERC a complaint, a request for declaratory order, or a change in rate.

D. Disputes Between PMC Members

For disputes between members of the PMC, the following dispute resolution procedures are to apply:

1. Initiating Dispute Resolution

The disputing PMC member(s) initiates its dispute by providing written notification to the PMC (or a designated sub-committee of the PMC) in accordance with the provisions of the Planning Participation Agreement, in which event the PMC will seek to resolve the dispute through discussion, negotiation and the development of a recommended course of action. The PMC may act to adopt a resolution recommended by its own committee members or sub-committees, or alternatively the disputing parties may act to refer the dispute to arbitration for resolution.

2. Arbitration

A dispute may be referred to arbitration under the governing provisions of the Planning Participation Agreement.

3. Resolution by FERC

The availability of the dispute resolution avenues identified above does not eliminate a disputing PMC member's(s') right under the Federal Power Act to refer either a procedural or substantive matter within the jurisdiction of FERC to FERC for resolution, for example by filing with FERC a complaint, a request for declaratory order or a change in rate.

VI. Cost Allocation

A. Local Transmission Projects

Local Transmission Projects are projects located within a Transmission Owner's retail distribution service territory or footprint unless such projects are submitted and selected in the Regional Plan for purposes of cost allocation. A Transmission Owner is not precluded from proposing Local Transmission Projects for inclusion in the Regional Plan for purposes of cost allocation in the Regional Planning Process. A Local Transmission Project that is not submitted or not selected for inclusion in the Regional Plan is not eligible for cost allocation in the Regional Plan, and not subject to the provisions governing regional cost allocation set forth below.

For any transmission project where Tri-State is the sole owner or such project is to be built within or for the benefit of the existing Tri-State system such as local, small and/or reliability transmission projects, Tri-State shall proceed with the project pursuant to its rights and obligations as a Transmission Provider for the local area. Any projects necessary to ensure reliability or that provide economic benefits to the Tri-State system and that fall outside the requirements for inclusion in the Regional Plan for purposes of cost allocation are eligible to be considered Local Transmission Projects.

Tri-State may share ownership, and associated costs, of any new transmission project, based upon mutual agreement between the parties. Such a joint ownership arrangement may arise because of existing joint ownership of facilities in the area of the new facilities, overlapping service territories, or other relevant considerations.

1. Open Season Solicitation of Interest

For any transmission project identified in a Tri-State reliability or economic planning study in which Tri-State is the project sponsor, Tri-State may elect to provide an "open season" solicitation of interest to secure additional project participants. Upon a determination by Tri-State to hold an open season solicitation of interest for a transmission project, Tri-State will:

Announce and solicit interest in the project through informational meetings, the Tri-State company website at: https://www.tristategt.org/transmission-planning website, and/or other means of dissemination as appropriate.

Hold meetings with interested parties, state public utility commission staffs from potentially affected states, and other affected stakeholders.

Post information via the Tri-State company website at: https://www.tristategt.org/transmission-planning.

Develop the initial transmission project specifications, the initial cost estimates and potential transmission line routes; guide negotiations and assist interested parties to determine cost responsibility for initial studies; guide the project through the applicable line siting processes; develop final project specifications and costs; obtain commitments from participants for final project cost shares; and secure execution of construction and operating agreements.

Whether as a project sponsor or a participant, coordinate as necessary with any other participant or sponsor, as the case may be, to integrate into Tri-State's Ten Year Transmission Plan any other planned project on or interconnected with Tri-State's transmission system.

B. Regional Transmission Projects

For any project determined by the PMC to be eligible for regional cost allocation, project costs will be allocated proportionally to those entities determined by the PMC, as shown in the Regional Plan, to be beneficiaries in the WestConnect Planning Region, as identified in this Attachment K, subject to the processes set forth in Sections III through VI.

The PMC, with input from the CAS, is to determine whether a project is eligible for regional cost allocation, and assesses the project's costs against its benefits in accordance with the following factors:

Benefits and beneficiaries will be identified before cost allocation methods are applied.

Cost assignments shall be commensurate with estimated benefits.

Those that receive no benefits must not be involuntarily assigned costs.

A benefit-to-cost threshold of not more than 1.25 shall be used, as applicable, so that projects with significant benefits are not excluded.

Costs must be allocated solely within the WestConnect Planning Region, unless other regions or entities voluntarily assume costs.

Costs for upgrades on neighboring transmission systems or other planning regions that are (i) required to be mitigated by the WECC Path Rating process, FERC tariff requirements, or NERC Reliability Standards, or (ii) negotiated among interconnected parties will be included in the total project costs and used in the calculation of B/C ratios.

Cost allocation method and data shall be transparent and with adequate documentation.

Different cost allocation methods may be used for different types of projects.

Specifically, the PMC will consider the following projects eligible for cost allocation consideration as further described below based on specified criteria:

Reliability projects;

Economic or congestion relief projects; or

Public policy projects.

Only projects that fall within one or more of these three categories and satisfy the cost-to-benefit analyses and other requirements, as specified herein, are eligible for cost allocation in the WestConnect Planning Region. Tri-State encourages all interested stakeholders to consult the Business Practice Manual for additional details regarding the assessment for eligibility for regional cost allocation. Summary provisions are provided below.

1. Allocation of Costs for Reliability Projects

In order to allocate costs to Transmission Owners for system reliability improvements that are necessary for their systems to meet the NERC TPL standards, the WestConnect cost allocation procedure shall allocate costs for system reliability improvements only when a system improvement is required to comply with the NERC TPL Reliability Standards during the planning horizon.

All components of a Transmission Owner's local transmission plan shall be included in the Regional Plan and shall be considered Local Transmission Projects that are not eligible for regional cost allocation. A system performance analysis shall be performed on the collective plans to ensure the combined plans adhere to all relevant NERC TPL Reliability Standards and stakeholders shall be afforded an opportunity to propose projects that are more efficient or cost-effective than components of multiple Transmission Owner local plans as outlined in Section III.F, above.

Should a reliability issue be identified in the review of the included local transmission plan, the project necessary to address that reliability issue shall be included in the Regional Plan and the cost shall be shared by the utilities whose load contributed to the need for the project.

Should multiple utilities have separate reliability issues that are addressed more efficiently or cost-effectively by a single regional project, that regional project shall be approved for selection in the Regional Plan and the cost shall be shared by those Transmission Owners in proportion to the cost of alternatives that could be pursued by the individual Transmission Owners to resolve the reliability issue. The ultimate responsibility for maintaining system reliability and compliance with NERC Transmission Planning Standards rests with each Transmission Owner.

The costs for regional reliability projects shall be allocated according to the following equation:

(1 divided by 2) times 3 equals 4

Where:

is the cost of local reliability upgrades necessary to avoid construction of the regional reliability project in the relevant Transmission Owner's retail distribution service territory or footprint

is the total cost of local reliability upgrades in the combination of Transmission Owners' retail distribution service territories or footprints necessary to avoid construction of the regional reliability project

is the total cost of the regional reliability project

is the total cost allocated to the relevant Transmission Owner's retail distribution service territory or footprint

The manner in which the PMC applied this methodology to allocate the costs of each regional reliability project shall be described in the Regional Plan.

2. Allocation of Costs for Economic Projects

Cost allocation for economic projects associated with congestion relief that provide for more economic operation of the system will be based on the calculation of economic benefits that each Transmission Owner system will receive. Cost allocation for economic projects shall include scenario analyses to ensure that benefits will actually be received by beneficiaries with relative certainty. Projects for which benefits and beneficiaries are highly uncertain and vary beyond reasonable parameters based on assumptions about future conditions will not be selected for cost allocation.

In order for a project to be considered economically-justified and receive cost allocation associated with economic projects, the project must have a B/C ratio that is greater than 1.0 under each reasonable scenario evaluated and have an average ratio of at least 1.25 under all reasonable scenarios evaluated. Costs will be allocated on the basis of the average of all scenarios evaluated. The B/C ratio shall be calculated by the PMC. This B/C ratio shall be determined by calculating the aggregate load-weighted benefit-to-cost ratio for each transmission system in the WestConnect Planning Region. The benefits methodology laid out below ensures that the entities that benefit the most from the completion of an economic project are allocated costs commensurate with those project benefits.

The cost of any project that has an aggregate 1.25 B/C ratio or greater will be divided among the Transmission Owners that show a benefit based on the amount of benefits calculated to each respective Transmission Owner. For example, if a $100 million dollar project is shown to have $150 million in economic benefit, the entities for which the economic benefit is incurred will be determined. The cost of the project will then be allocated to those entities, based on the extent of each entity's economic benefits relative to the total project benefits. This will ensure that each entity that is allocated cost has a B/C ratio equal to the total project B/C ratio. For example:

- Project with $150 million in economic benefit and $100 million in cost
    - Company 1 has $90 million in benefits; Company 2 has $60 million in benefits
    - Company 1 allocation: 90/150 (100) = $60 million
    - Company 1 B/C ratio: 90/60 = 1.5
    - Company 2 allocation: 60/150 (100) = $40 million
    - Company 2 B/C ratio: 60/40 = 1.5

Other than through the reevaluation process described in Section III.J of this Attachment K, the benefits and costs used in the evaluation shall only be calculated during the planning period and shall be compared on a net present value basis.

The WestConnect economic planning process shall consider production cost savings and reduction in reserve sharing requirements as economic benefits capable of contributing to the determination that a project is economically justified for cost allocation. Production cost savings are to be determined by the PMC performing a product cost simulation to model the impact of the transmission project on production costs and congestion. Production cost savings will be calculated as the reduction in production costs between a production cost simulation with the project included compared to a simulation without the project. Reductions in reserve sharing requirements are to be determined by the PMC identifying a transmission project's impact on the reserve requirements of individual transmission systems, and not on the basis of the project's collective impact on a reserve sharing group, as a whole. The production cost models are to appropriately consider the hurdle rates between transmission systems. The following production cost principles may be applied:

The production cost savings from a project must be present in each year from the project in-service date and extending out at least ten (10) years.

Cost savings must be expressed in present-value dollars and should consider the impact of various fuel cost forecasts.

The production cost study must account for contracts and agreements related to the use of the transmission system (this refers to paths in systems that might be contractually limited but not reliability limited).

The production cost study must account for contracts and agreements related to the access and use of generation (this refers to generators that might only use spot purchases for fuel rather than firm purchases, or generation that has been designated as network resources for some entities and thus cannot be accessed at will by non-owners).

Access by stakeholders to the PMC's application of its regional cost allocation method for a specific economic transmission project is available in several ways: First, stakeholders that are members of the PMC will have firsthand knowledge of the way in which the regional method was applied to a particular project because the PMC is responsible for performing the application of the regional cost allocation method. Second, stakeholders that choose not to become members of the PMC may access such information through the WestConnect regional stakeholder process. See Section III.B of this Attachment K. Third, the manner in which the PMC applied this methodology to allocate the costs of each economic project shall be described in the Regional Plan.

In determining which entities shall be allocated costs for economic projects, WestConnect shall compare the economic value of benefits received by an entity with the cost of the project to ensure that each entity allocated cost receives a benefit/cost ratio equal to the aggregate load-weighted benefit-to-cost ratio. These costs allocated to each company shall be calculated based on the following equation:

(1 divided by 2) times 3 equals 4

Where:

is the total projected present value of economic benefits for the relevant Transmission Owner

is the total projected present value of economic benefits for the entire project

is the total cost of the economic project

is the total cost allocated to the relevant Transmission Owner

Any Transmission Owner with benefits less than or equal to one percent of total project benefits shall be excluded from cost allocation. Where a project satisfies the B/C ratio, and is determined to provide benefits less than or equal to one percent of total project benefits to an identified Transmission Owner, such benefits will be re-allocated to all other identified beneficiaries on a pro rata basis, in relation to each entity's share of total project benefits.

3. Allocation of Costs for Public Policy Projects

Any transmission system additions that arise from Public Policy Requirements shall be included in the system models used for the WestConnect transmission system studies. Further, any additional system needs that arise from proposed public policy shall be reported by each entity for its own service territory. Decisions on the inclusion of those needs shall be made during the consideration and approval of the system models. Transmission needs driven by Public Policy Requirements will be included in the evaluation of reliability and economic projects.

Except for projects proposed through a Transmission Owner's local planning process, arising out of a local need for transmission infrastructure to satisfy Public Policy Requirements that are not submitted as projects proposed for cost allocation (which are addressed in Section II of this Attachment K), any projects arising out of a regional need for transmission infrastructure to satisfy the Public Policy Requirements shall be considered public policy projects eligible for evaluation in the Regional Planning Process.

Stakeholders may participate in identifying regional transmission needs driven by Public Policy Requirements. After seeking the input of stakeholders pursuant to the stakeholder participation provisions of Section III, the PMC is to determine whether to move forward with the identification of a regional solution to a particular regional need driven by Public Policy Requirements. Stakeholders may participate in identifying a regional solution to a regional need driven by Public Policy Requirements pursuant to the stakeholder participation provisions of Section III, or through membership on the PMC itself. After seeking the input of stakeholders, the PMC is to determine whether to select a particular regional solution in the regional transmission plan for purposes of cost allocation. The identification of beneficiaries of these projects shall be the entities that shall access the resources enabled by the project in order to meet their Public Policy Requirements.

If an entity accesses resources that were enabled by a prior public policy project, that entity shall need to either share in its relative share of the costs of that public policy project or acquire sufficient transmission service rights to move the resources to its load with the determination left up to the entity or entities that were originally allocated the cost for the public policy project. The costs for public policy projects shall be allocated according to the following equation:

(1 divided by 2) times 3 equals 4

Where:

is the number of megawatts of public policy resources enabled by the public policy project for the entity in question

is the total number of megawatts of public policy resources enabled by the public policy project

is the total project cost

is the cost for the public policy project allocated to the entity in question

The process to interconnect individual generation resources would be provided for under the generator interconnection section each utility's OATT and not under this process.

Requests for transmission service that originate in a member's system and terminate at the border shall be handled through that member's OATT. Regional transmission needs necessary to meet Public Policy Requirements shall be addressed through the Public Policy Requirements section of the Regional Planning Process.

The manner in which WestConnect applied this methodology to each public policy project shall be described in the Regional Transmission Plan.

4. Combination of Benefits

In developing a more efficient or cost-effective plan, it is possible for the plan to jointly consider multiple types of benefits when approving projects for inclusion in the Regional Plan. The determination to consider multiple types of benefits for a particular project shall be made through the WestConnect stakeholder process, in which interested stakeholders are given an opportunity to provide input as set forth in Section III of this Attachment K. In determining whether a project would provide multiple benefits, the PMC is to categorize the benefits as (a) necessary to meet NERC Transmission Planning Reliability Standards (reliability); (b) achieving production cost savings or a reduction in reserve sharing requirements (economic); or (c) necessary to meet transmission needs driven by Public Policy Requirements, as applicable, using the methods set forth in this Attachment K. The PMC will identify all three categories of benefits in its regional cost allocation process. If a project cannot pass the cost allocation threshold for any one of the three benefit categories, alone (reliability, economic or public policy), the sum of benefits from each benefit category may be considered.

With respect to a reliability-driven regional transmission project, the quantified benefits of the project to each identified beneficiary must be greater, by a margin of 1.25 to 1, than the result of the equation identified in Section VI.B.1 above (where the result is shown as item 4 in the formula).

With respect to an economic-driven regional transmission project, the quantified benefits of the project to each identified beneficiary must be greater than the project's cost to each beneficiary under each reasonable scenario evaluated, and must yield an average ratio of at least 1.25 to 1 under all reasonable scenarios evaluated, as described in Section VI.B.2 above.

With respect to a Public Policy Requirements-driven regional transmission project, the quantified benefits of the project to each identified beneficiary must be greater, by a margin of 1.25 to 1, than the result of the equation identified in Section VI.B.3 above (where the result is shown as item 4 in the formula).

If a single regional transmission project is determined to provide benefits in more than one category, but does not meet the cost-benefit threshold for any single category, the PMC may consider the sum of benefits from each benefit category to determine if the regional transmission project provides, in total, benefits per beneficiary that meet or exceed the region's 1.25 to 1 benefit to cost ratio. To illustrate, consider the following example where a regional project developed to provide public policy requirement benefits might also provide for economic benefits to the same beneficiaries:

A regional project submittal has undergone analysis for its quantifiable benefits and costs and is determined to cost $100 million and produce benefits to identified beneficiaries in two categories: economic benefits of $101 million (on average, under all economic scenarios quantified), and public policy requirement benefits of $70 million. The project is found to fail the cost-benefit threshold for each category, individually, but when the total benefits are combined and the project's total regional benefits per beneficiary are weighed against the project's total costs per beneficiary, the project can be found to meet or surpass the region's 1.25 to 1 benefit to cost ratio per beneficiary:

The benefits to Beneficiary A of pursuing the regional solution (60% of the regional project's total $171 million in benefits) = $102.6 million. When $102.6 million in project benefits is compared against $60 million in project costs (60% of project costs), it yields a B/C ratio of 1.71 to 1 for Beneficiary A.

The benefits to Beneficiary B of pursuing the regional solution (40% of the regional project's total $171 million in benefits) = $68.4 million. When $68.4 million in project benefits is compared against $40 million in project costs (40% of project costs), it yields a B/C ratio of 1.71 to 1 for Beneficiary B.

Even though the regional project does not pass the cost allocation threshold in any individual benefit category, the PMC may consider the sum of the project's benefits in all categories.

For those regional projects that satisfy the region's cost allocation threshold, the PMC then will continue its evaluation process by considering whether the regional project meets the region's identified reliability, economic and Public Policy Requirements-driven needs more efficiently or cost-effectively than solutions identified by individual transmission providers in their local transmission planning processes.

The costs for projects that rely upon multiple types of benefits to secure inclusion in the Regional Plan for purposes of cost allocation shall be shared according to the amount of cost that is justified by each type of benefit.

5. Allocation of Ownership and Capacity Rights

An Eligible Transmission Developer that is subject to the Commission's jurisdiction under Section 205 of the Federal Power Act may not recover project costs from identified beneficiaries in the WestConnect Planning Region without securing approval for project cost recovery from FERC through a separate proceeding brought by the Eligible Transmission Developer under Section 205 of the Federal Power Act. In no event will identified beneficiaries in the WestConnect Planning Region from whom project costs are sought to be recovered under Section 205 be denied either transmission transfer capability or ownership rights proportionate to their allocated costs, as determined by FERC in such proceeding. An Eligible Transmission Developer that is not subject to the Commission's jurisdiction under Section 205 of the Federal Power Act would have to seek cost recovery from identified beneficiaries in the WestConnect Planning Region either: (a) through bilateral agreements that are voluntarily entered into between such Eligible Transmission Developer and the applicable identified beneficiaries; or (b) by obtaining approval from FERC for project cost recovery pursuant to any other applicable section of the Federal Power Act.

If a project beneficiary receives transmission transfer capability on the project in exchange for transmission service payments, such project beneficiary may resell the transfer capability. Alternatively, a project beneficiary could seek to make a direct capital contribution to the project construction cost (in lieu of making transmission service payments) in which case the project beneficiary would instead receive an ownership percentage in proportion to their capital contribution ("Ownership Proposal"). This Ownership Proposal does not create a right of first refusal for transmission beneficiaries.

An ownership alternative will only be pursued if the Eligible Transmission Developer agrees. The Eligible Transmission Developer and the beneficiaries will enter into contract negotiations to address the many details regarding the capital funding mechanics and timing, as well as other details, such as defining (as between the Eligible Transmission Developer, whether a nonincumbent or incumbent transmission developer, and those receiving ownership interests) responsibility for operations and maintenance, administrative tasks, compliance with governing laws and regulations, etc. These negotiations will take place at arm's length, without any one party having undue leverage over the other.

A transmission project beneficiary should not be expected to pay for its benefits from the project twice: once through a capital contribution, and again through transmission service payments. The Ownership Proposal permits an ownership share in a project that is in the same proportion to a beneficiary's allocable costs, which costs will have been allocated roughly commensurate with the benefits to be gained from the project. This will allow the beneficiary to earn a return on its investment. In addition, it allows those beneficiaries that may not necessarily benefit from additional transfer capability on a new transmission project, whether due to lack of contiguity to the new facilities or otherwise, to realize the benefits through an ownership option.

Any transmission project participant that is identified as a beneficiary of the project might be permitted by the Eligible Transmission Developer to contribute capital (in lieu of transmission service payments) and receive a proportionate share of ownership rights in the transmission project. The Ownership Proposal affords an identified beneficiary who contributes toward the project costs the opportunity to obtain an ownership interest in lieu of an allocated share of the project costs through transmission service payments for transfer capability on the project; it does not, however, confer a right to invest capital in a project. The Ownership Proposal merely identifies that, to the extent it is agreed among the parties that capital may be contributed toward a transmission project's construction, a proportionate share of ownership rights will follow.

Nothing in this Attachment K with respect to Order No. 1000 cost allocation imposes any new service on beneficiaries. Similarly, nothing in this Attachment K with respect to Order No. 1000 cost allocation imposes on an Eligible Transmission Developer an obligation to become a provider of transmission services to identified beneficiaries simply as a result of a project's having been selected in the Regional Plan for purposes of cost allocation; provided, however, if that Eligible Transmission Developer seeks authorization to provide transmission services to beneficiaries or others, and to charge rates or otherwise recover costs from beneficiaries or others associated with any transmission services it were to propose, it must do so by contract and/or under separate proceedings under the Federal Power Act. The purpose of this Section VI.B.5 is to (a) provide an option to a project developer to negotiate ownership rights in the project with identified beneficiaries, if both the developer and the identified beneficiaries mutually desire to do so, (b) specify that, although Order No. 1000 cost allocation does not impose any new service on beneficiaries, identified beneficiaries have the opportunity to discuss with the project developer the potential for entering into transmission service agreements for transmission capacity rights in the project, and (c) ensure that Order No. 1000 cost allocation does not mean that a project developer may recover project costs from identified beneficiaries without providing transmission transfer capability or ownership rights, and without securing approval for project cost recovery by contract and/or under a separate proceeding under the Federal Power Act.

6. Project Development Schedule

The WestConnect PMC will not be responsible for managing the development of any project selected for inclusion in the Regional Plan. However, after having selected a project in the Regional Plan, the PMC will monitor the status of the project's development. If a transmission facility is selected for inclusion in the Regional Plan for purposes of cost allocation, the transmission developer of that transmission facility must submit a development schedule that indicates the required steps, such as the granting of state approvals, necessary to develop and construct the transmission facility such that it meets the regional transmission needs of the WestConnect Planning Region. As part of the ongoing monitoring of the status of the transmission project once it is selected, the Transmission Owners and Providers in the WestConnect Planning Region shall establish the dates by which the required steps to construct must be achieved that are tied to when construction must begin to timely meet the need that the project is selected to address. If such required steps have not been achieved by those dates, then the Transmission Owners and Providers in the WestConnect Planning Region may remove the transmission project from the selected category and proceed with reevaluating the Regional Plan to seek an alternative solution.

7. Economic Benefits or Congestion Relief

For a transmission project wholly within the Transmission Provider's local transmission system that is undertaken for economic reasons or congestion relief at the request of a Requester, the project costs will be allocated to the Requester. A "Requester" is defined as any Tri-State transmission customer or other stakeholder, including sponsors of transmission solutions, generation solutions and solutions utilizing demand response resources.

8. Tri-State Rate Recovery

Notwithstanding the foregoing provisions, Tri-State shall not assume cost responsibility for any transmission project if the cost of the project is not reasonably expected to be recoverable in Tri-State's wholesale transmission rates.

9. Selection of a Transmission Developer for Sponsored and Unsponsored Projects

For any project (sponsored or unsponsored) determined by the PMC to be eligible for regional cost allocation and selected in the Regional Plan for purposes of cost allocation, the PMC shall select a transmission project developer according to the processes set forth in this section, provided that selection according to those processes does not violate applicable law where the transmission facility is to be built that otherwise prescribes the entity that shall develop and build the project. Any entity that, pursuant to applicable law for the location where the facilities are to be built, shall or chooses to develop and build the project must submit a project development schedule as required by Section VI.B.6 of this Attachment K, within the timeframe directed by the Business Practice Manual, not to exceed the time period for request for proposal responses.

For any project determined by the PMC to be eligible for regional cost allocation and selected in the Regional Plan for purposes of cost allocation, either sponsored by a transmission developer or unsponsored, that is not subject to the foregoing paragraph, the PMC shall upon posting the selected projects, issue a request for information to all Eligible Transmission Developers under Section III.D.3 of this Attachment K soliciting their interest in developing the project(s).

Each transmission developer shall respond to the request for information indicating its interest in developing the project. The PMC shall post on the WestConnect website the list of all transmission developers who responded with an expression of interest in developing the project(s). The PMC shall provide to each developer indicating interest in developing a project a request for proposals for the identified project(s) with a specified date of return for all proposals. Each transmission developer, or partnership or joint ventures of transmission developers, shall submit information demonstrating its ability to finance, own and construct the project consistent with the guidelines for doing so set forth in the WestConnect Business Practices Manual. The PMC shall assess the submissions according to the following process and criteria:

The evaluation of the request for proposals will be at the direction of the PMC, and will involve representatives of the beneficiaries of the proposed project(s). The evaluation will include, but not be limited to, an assessment of the following evidence and criteria.

- General qualifications of the bidding entity;
- Evidence of financing/financial creditworthiness, including
    - financing plan (sources debt and equity), including construction financing and long-term financing
    - ability to finance restoration/forced outages
    - credit ratings
    - financial statements;
- Safety program and experience;

- Project description, including
  - detailed proposed project description and route
  - design parameters
  - design life of equipment and facilities
  - description of alternative project variations;
- Development of project, including
  - experience with and current capabilities and plan for obtaining state and local licenses, permits, and approvals
  - experience with and current capabilities and plan for obtaining any federal licenses and permits
  - experience with and expertise and plan for obtaining rights of way
  - development schedule
  - development budget;
- Construction, including
  - experience with and current capabilities and plan for project construction
  - third party contractors
  - procurement plan
  - project management (cost and schedule control)
  - construction schedule
  - construction budget (including all construction and period costs;
- Operations, including
  - experience with and current capabilities and plan for project operation
  - experience with and current capabilities and plan for NERC compliance
  - security program and plan
  - storm/outage response plan
  - reliability of facilities already in operation;
- Maintenance capabilities and plans for project maintenance (including staffing, equipment, crew training, and facilities);
- Project cost to beneficiaries, including
  - total project cost (development, construction, financing, and other non-O&M costs)
  - operation and maintenance costs, including evaluation of electrical losses
  - revenue requirement, including proposed cost of equity, FERC incentives, proposed cost of debt and total revenue requirement calculation
  - present value cost of project to beneficiaries.

The PMC shall notify the developers of its determination as to which developer(s) it selected to develop the project(s) responsive to the request for proposal. The selected developer(s) must submit a project development schedule as required by Section VI.B.6 of this Attachment K.

If the PMC determines that a sponsored or unsponsored project fails to secure a developer through the process outlined in this section, the PMC shall remove the project from the Regional Plan.

After the PMC makes a determination, it will post a document on the WestConnect website within 60 days explaining the PMC's determination in selecting a particular transmission developer for a specific transmission project. The information will explain (1) the reasons why a particular transmission developer was selected or not selected, and, if applicable, (2) the reasons why a transmission project failed to secure a transmission developer.

10. No Obligation to Construct

The Regional Planning Process is intended to determine and recommend more efficient or cost-effective transmission solutions for the WestConnect Planning Region. After the Regional Plan is approved, due to the uncertainty in the planning process and the need to address cost recovery issues, the Regional Planning Process shall not obligate any entity to construct, nor obligate any entity to commit to construct, any facilities, including any transmission facilities, regardless of whether such facilities are included in any plan. Nothing in this Attachment K or the Planning Participation Agreement or any cost allocation under the Business Practice Manual or the Planning Participation Agreement will (1) determine any transmission service to be received by, or any transmission usage by, any entity, (2) obligate any entity to purchase or pay for, or obligate any entity to commit to purchase or pay for, any transmission service or usage, or (3) entitle any entity to recover for any transmission service or usage or to recover from any entity any cost of any transmission facilities, regardless of whether such transmission facilities are included in any plan. Without limiting the generality of the foregoing, nothing in this Attachment K, the Business Practice Manual or the Planning Participation Agreement with respect to an Order No. 1000 cost allocation shall preclude WestConnect or any other entity from carrying out any of its statutory authorities or complying with any of its statutory obligations.

11. Binding Order No. 1000 Cost Allocation Methods

Order No. 1000 cost allocation methods as set forth in Section VI of this Attachment K are binding on identified beneficiaries enrolled in the WestConnect Planning Region, without prejudice to the following rights and obligations: (1) the right of a CTO, at its sole discretion, to decide whether to accept regional cost allocation in accordance with Section III.J; (2) the right and obligation of the PMC to reevaluate a transmission facility previously selected for inclusion in the regional plan for purposes of Order No. 1000 cost allocation under Section III.K of this Attachment K; (3) the right and obligation of an Eligible Transmission Developer to make a filing under Section 205 or other applicable provision of the Federal Power Act in order to seek approval from the Commission to recover the costs of any transmission facility selected for inclusion in the regional plan for purposes of Order No. 1000 cost allocation; (4) the right and obligation of any interested person to intervene and be heard before the Commission in any Section 205 or other applicable provision proceeding initiated by an Eligible Transmission Developer, including the right of any identified beneficiaries of the transmission facility to support or protest the filing and to present evidence on whether the proposed cost recovery is or is not just and reasonable; and (5) the right and obligation of the Commission to act under Section 205 or other applicable provisions of the Federal Power Act to approve or deny any cost recovery sought by an Eligible Transmission Developer for a transmission facility selected in the regional plan for purposes of Order No. 1000 cost allocation.

12. Impacts of a Regional Project on Neighboring Planning Regions

The PMC is to study the impact(s) of a regional transmission project on neighboring planning regions, including the resulting need, if any, for mitigation measures in such neighboring planning regions. If the PMC finds that a regional transmission project in the WestConnect Planning Region causes impacts on a neighboring planning region that requires mitigation (a) by the WECC Path Rating Process, (b) under FERC OATT requirements, (c) under NERC Reliability Standards requirements, and/or (d) under any negotiated arrangement between the interconnected entities, the PMC is to include the costs of any such mitigation measures into the regional transmission project's total project costs for purposes of determining the project's eligibility for regional cost allocation under the procedures identified in Section VI.B of this Attachment K, including application of the region's benefits-to-costs analysis.

The WestConnect Planning Region will not be responsible for compensating a neighboring planning region, Transmission Provider, Transmission Owner, Balancing Area Authority, or any other entity, for the costs of any required mitigation measures, or other consequences, on their systems associated with a regional transmission project in the WestConnect Planning Region, whether identified by the PMC or the neighboring system(s). The PMC does not direct the construction of transmission facilities, does not operate transmission facilities or provide transmission services, and does not charge or collect revenues for the performance of any transmission or other services. Therefore, in agreeing to study the impacts of a regional transmission facility on neighboring planning regions, the PMC is not agreeing to bear the costs of any mitigation measures it identifies. However, the PMC will request of any developer of a regional transmission project selected in the Regional Plan for purposes of cost allocation that the developer design and build its project to mitigate the project's identified impacts on neighboring planning regions. If the project is identified as impacting a neighboring planning region that accords less favorable mitigation treatment to the WestConnect Planning Region than the WestConnect Planning Region accords to it, the PMC will request that the project developer reciprocate by using the lesser of (i) the neighboring region's mitigation treatment applicable to the mitigation of impacts of its own regional projects on the WestConnect Planning Region, or (ii) the PMC's mitigation treatment set forth above in sub-sections (a) through (d).

13. Exclusions

The cost for transmission projects undertaken in connection with requests for generation interconnection or transmission service on the Tri-State transmission system, which are governed by existing cost allocation methods within the OATT, shall continue to be so governed and shall not be subject to the principles of this Section VI.

As provided in Section 13.5 (Transmission Customer Obligations for Facility Additions or Redispatch Costs), Section 27 (Compensation for New Facilities and Redispatch Costs) and Section 31.2 (New Network Loads Connected with the Transmission Provider) of the OATT, and the Transmission Customer's individual service agreement (if applicable), the Transmission Customer or Requester shall be responsible for the installed cost of all new load serving interconnections or upgrades to existing load serving interconnections.

VII. Interregional Planning

This Part VII of Attachment K sets forth common provisions, which are to be adopted by or for each Planning Region and which facilitate the implementation of Order No. 1000 interregional provisions. WestConnect is to conduct the activities and processes set forth in this Part VII of this part of Attachment K in accordance with the provisions of this Part VII of this part of Attachment K and the other provisions of this Attachment K. Nothing in this part will preclude any transmission owner or transmission provider from taking any action it deems necessary or appropriate with respect to any transmission facilities it needs to comply with any local, state, or federal requirements. Any Interregional Cost Allocation regarding any ITP (as defined herein) is solely for the purpose of developing information to be used in the regional planning process of each Relevant Planning Region, including the regional cost allocation process and methodologies of each such Relevant Planning Region. References in this Part VII to any transmission planning processes, including cost allocations, are references to transmission planning processes pursuant to Order No. 1000.

A. Definitions

The following capitalized terms where used in this Part VII of Attachment K, are defined as follows:

Annual Interregional Coordination Meeting: shall have the meaning set forth in Section VII.C below.

Annual Interregional Information: shall have the meaning set forth in Section VII.B below.

Interregional Cost Allocation: means the assignment of ITP costs between or among Planning Regions as described in Section VII.E.2 below.

Interregional Transmission Project ("ITP"): means a proposed new transmission project that would directly interconnect electrically to existing or planned transmission facilities in two or more Planning Regions and that is submitted into the regional transmission planning processes of all such Planning Regions in accordance with Section VII.D.1.

Order 1000 Common Interregional Coordination and Cost Allocation Tariff Language: means this Part VII, which relates to Order No. 1000 interregional provisions.

Planning Region: means each of the following Order No. 1000 transmission planning regions insofar as they are within the Western Interconnection: California Independent System Operator Corporation, ColumbiaGrid, Northern Tier Transmission Group, and WestConnect.

Relevant Planning Regions: means, with respect to an ITP, the Planning Regions that would directly interconnect electrically with such ITP, unless and until such time as a Relevant Planning Region determines that such ITP will not meet any of its regional transmission needs in accordance with Section VII.D.2, at which time it shall no longer be considered a Relevant Planning Region.

B. Annual Interregional Information Exchange

Annually, prior to the Annual Interregional Coordination Meeting, WestConnect is to make available by posting on its website or otherwise provide to each of the other Planning Regions the following information, to the extent such information is available in its regional transmission planning process, relating to regional transmission needs in WestConnect's transmission planning region and potential solutions thereto:

(i) study plan or underlying information that would typically be included in a study plan, such as:
  (a) identification of base cases;
  (b) planning study assumptions; and
  (c) study methodologies;
(ii) initial study reports (or system assessments); and
(iii) regional transmission plan

(collectively referred to as "Annual Interregional Information").

WestConnect is to post its Annual Interregional Information on its website according to its regional transmission planning process. Each other Planning Region may use in its regional transmission planning process WestConnect's Annual Interregional Information. WestConnect may use in its regional transmission planning process Annual Interregional Information provided by other Planning Regions.

WestConnect is not required to make available or otherwise provide to any other Planning Region (i) any information not developed by WestConnect in the ordinary course of its regional transmission planning process, (ii) any Annual Interregional Information to be provided by any other Planning Region with respect to such other Planning Region, or (iii) any information if WestConnect reasonably determines that making such information available or otherwise providing such information would constitute a violation of the Commission's Standards of Conduct or any other legal requirement. Annual Interregional Information made available or otherwise provided by WestConnect shall be subject to applicable confidentiality and CEII restrictions and other applicable laws, under WestConnect's regional transmission planning process. Any Annual Interregional Information made available or otherwise provided by WestConnect shall be "AS IS" and any reliance by the receiving Planning Region on such Annual Interregional Information is at its own risk, without warranty and without any liability of WestConnect, including any liability for (a) any errors or omissions in such Annual Interregional Information, or (b) any delay or failure to provide such Annual Interregional Information.

C. Annual Interregional Coordination Meeting

WestConnect is to participate in an Annual Interregional Coordination Meeting with the other Planning Regions. WestConnect is to host the Annual Interregional Coordination Meeting in turn with the other Planning Regions, and is to seek to convene such meeting in February, but not later than March 31st. The Annual Interregional Coordination Meeting is to be open to stakeholders. WestConnect is to provide notice of the meeting to its stakeholders in accordance with its regional transmission planning process.

At the Annual Interregional Coordination Meeting, topics discussed may include the following:

each Planning Region's most recent Annual Interregional Information (to the extent it is not confidential or protected by CEII or other legal restrictions);

identification and preliminary discussion of interregional solutions, including conceptual solutions, that may meet regional transmission needs in each of two or more Planning Regions more cost effectively or efficiently; and

updates of the status of ITPs being evaluated or previously included in WestConnect's regional transmission plan.

D. ITP Joint Evaluation Process

1. Submission Requirements

A proponent of an ITP may seek to have its ITP jointly evaluated by the Relevant Planning Regions pursuant to Section VII.D.2 by submitting the ITP into the regional transmission planning process of each Relevant Planning Region in accordance with such Relevant Planning Region's regional transmission planning process and no later than March 31st of any even-numbered calendar year. Such proponent of an ITP seeking to connect to a transmission facility owned by multiple transmission owners in more than one Planning Region must submit the ITP to each such Planning Region in accordance with such Planning Region's regional transmission planning process. In addition to satisfying each Relevant Planning Region's information requirements, the proponent of an ITP must include with its submittal to each Relevant Planning Region a list of all Planning Regions to which the ITP is being submitted.

2. Joint Evaluation of an ITP

For each ITP that meets the requirements of Section VII.D.1, WestConnect (if it is a Relevant Planning Region) is to participate in a joint evaluation by the Relevant Planning Regions that is to commence in the calendar year of the ITP's submittal in accordance with Section VII.D.1 or the immediately following calendar year. With respect to any such ITP, WestConnect (if it is a Relevant Planning Region) is to confer with the other Relevant Planning Region(s) regarding the following:

ITP data and projected ITP costs; and

the study assumptions and methodologies it is to use in evaluating the ITP pursuant to its regional transmission planning process.

For each ITP that meets the requirements of Section VII.D.1, WestConnect (if it is a Relevant Planning Region):

is to seek to resolve any differences it has with the other Relevant Planning Regions relating to the ITP or to information specific to other Relevant Planning Regions insofar as such differences may affect WestConnect's evaluation of the ITP;

is to provide stakeholders an opportunity to participate in WestConnect's activities under this Section VII.D.2 in accordance with its regional transmission planning process;

is to notify the other Relevant Planning Regions if WestConnect determines that the ITP will not meet any of its regional transmission needs; thereafter WestConnect has no obligation under this Section VII.D.2 to participate in the joint evaluation of the ITP; and

is to determine under its regional transmission planning process if such ITP is a more cost effective or efficient solution to one or more of WestConnect's regional transmission needs.

E. Interregional Cost Allocation Process

1. Submission Requirements

For any ITP that has been properly submitted in each Relevant Planning Region's regional transmission planning process in accordance with Section VII.D.1, a proponent of such ITP may also request Interregional Cost Allocation by requesting such cost allocation from WestConnect and each other Relevant Planning Region in accordance with its regional transmission planning process. The proponent of an ITP must include with its submittal to each Relevant Planning Region a list of all Planning Regions in which Interregional Cost Allocation is being requested.

2. Interregional Cost Allocation Process

For each ITP that meets the requirements of Section VII.E.1, WestConnect (if it is a Relevant Planning Region) is to confer with or notify, as appropriate, any other Relevant Planning Region(s) regarding the following:

assumptions and inputs to be used by each Relevant Planning Region for purposes of determining benefits in accordance with its regional cost allocation methodology, as applied to ITPs;

WestConnect's regional benefits stated in dollars resulting from the ITP, if any; and

assignment of projected costs of the ITP (subject to potential reassignment of projected costs pursuant to Section VII.F.2 below) to each Relevant Planning Region using the methodology described in this Section VII.E.2.

For each ITP that meets the requirements of Section VII.E.1, WestConnect (if it is a Relevant Planning Region):

is to seek to resolve with the other Relevant Planning Regions any differences relating to ITP data or to information specific to other Relevant Planning Regions insofar as such differences may affect WestConnect's analysis;

is to provide stakeholders an opportunity to participate in WestConnect's activities under this Section VII.E.2 in accordance with its regional transmission planning process;

is to determine its regional benefits, stated in dollars, resulting from an ITP; in making such determination of its regional benefits in WestConnect, WestConnect is to use its regional cost allocation methodology, as applied to ITPs;

is to calculate its assigned *pro rata* share of the projected costs of the ITP, stated in a specific dollar amount, equal to its share of the total benefits identified by the Relevant Planning Regions multiplied by the projected costs of the ITP;

is to share with the other Relevant Planning Regions information regarding what its regional cost allocation would be if it were to select the ITP in its regional transmission plan for purposes of Interregional Cost Allocation; WestConnect may use such information to identify its total share of the projected costs of the ITP to be assigned to WestConnect in order to determine whether the ITP is a more cost effective or efficient solution to a transmission need in WestConnect;

is to determine whether to select the ITP in its regional transmission plan for purposes of Interregional Cost Allocation, based on its regional transmission planning process; and

is to endeavor to perform its Interregional Cost Allocation activities pursuant to this Section VII.E.2 in the same general time frame as its joint evaluation activities pursuant to Section VII.D.2.

F. Application of Regional Cost Allocation Methodology to Selected ITP

1. Selection by All Relevant Planning Regions

If WestConnect (if it is a Relevant Planning Region) and all of the other Relevant Planning Regions select an ITP in their respective regional transmission plans for purposes of Interregional Cost Allocation, WestConnect is to apply its regional cost allocation methodology to the projected costs of the ITP assigned to it under Section VII.E.2(d) or VII.E.2(e) above in accordance with its regional cost allocation methodology, as applied to ITPs.

2. Selection by at Least Two but Fewer than All Relevant Regions

If WestConnect (if it is a Relevant Planning Region) and at least one, but fewer than all, of the other Relevant Planning Regions select the ITP in their respective regional transmission plans for purposes of Interregional Cost Allocation, WestConnect is to evaluate (or reevaluate, as the case may be) pursuant to Sections VII.E.2(d), VII.E.2(e), and VII.E.2(f) above whether, without the participation of the non-selecting Relevant Planning Region(s), the ITP is selected (or remains selected, as the case may be) in its regional transmission plan for purposes for Interregional Cost Allocation. Such reevaluation(s) are to be repeated as many times as necessary until the number of selecting Relevant Planning Regions does not change with such reevaluation.

If following such evaluation (or reevaluation), the number of selecting Relevant Planning Regions does not change and the ITP remains selected for purposes of Interregional Cost Allocation in the respective regional transmission plans of WestConnect and at least one other Relevant Planning Region, WestConnect is to apply its regional cost allocation methodology to the projected costs of the ITP assigned to it under Sections VII.E.2(d) or VII.E.2(e) above in accordance with its regional cost allocation methodology, as applied to ITPs.

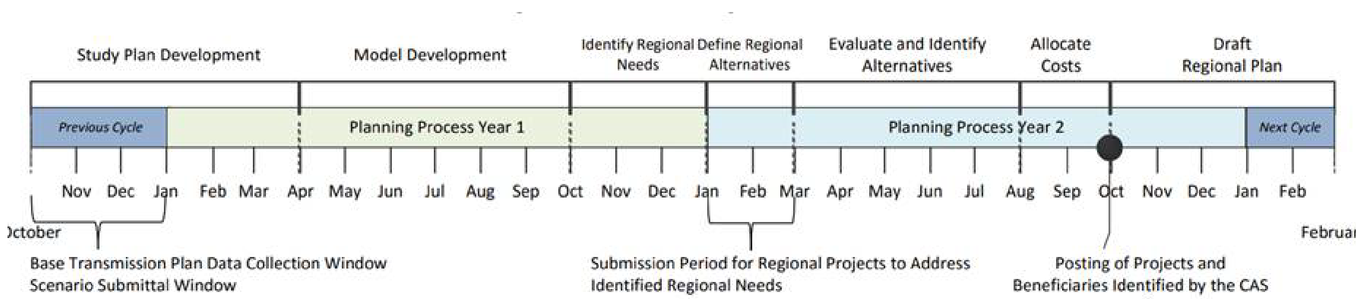
VIII. Recovery of Planning Costs

Tri-State's costs associated with the Regional Planning Process, including WestConnect's participation in interregional planning under Part VII, shall be recovered through existing rate structures. The costs for any local economic planning study shall be paid for by the Requester of those studies, as set forth in Section II.D.6. Any costs incurred by stakeholders for their participation in the Tri-State local planning processes shall be borne by those stakeholders.

For the costs of studies associated with specific wholesale delivery point requests by NITS or PTP customers taking service under the OATT, the requesting customer shall be responsible for the actual costs of such studies. The customer shall pay the full estimated cost prior to Tri-State beginning the study, and Tri-State shall either refund any over-collection or bill any under-collection after completion of the study.

EXHIBIT 1 TO ATTACHMENT K

WestConnect Planning Timeline



Long-Term Load Forecast Process

Long-Term Load forecasts are updated annually. The load forecasts are jointly prepared by Tri-State and each of its Members. Each customer class, for each Member, is individually evaluated and forecast.

The load forecast includes two alternative forecasts that reflect high and low loads resulting from weather extremes, and two other alternative forecasts resulting from high and low economic activity.

The base case and alternative forecasts for the members are summarized into several regions for use in load and resource planning models.

Tri-State Generation & Transmission Association, Inc.

Available Transfer Capability Implementation Document (ATCID)

Determination and Posting of Total Transfer Capability (TTC) and Available Transfer Capability (ATC)

June 12, 2022

1. PURPOSE

The Available Transfer Capability Implementation Document (ATCID) provides the documentation of required information as specified in the NERC Modeling, Data, and Analysis (MOD) Standards and the NAESB OASIS Standards, regarding the calculation methodology and information sharing of Available Transfer Capability (ATC) specific to this Transmission Provider.

2. GENERAL OVERVIEW

Tri-State Generation and Transmission Association, Inc. (TSGT) has over 5,200 miles of Transmission in the WECC and MRO Regions, primarily located in the states of Wyoming, Colorado, New Mexico, and Nebraska. The TSGT Transmission System is characterized by geographically separated load serving regions which are dependent, to a great extent, upon other Transmission Providers to serve its' member loads. Many of TSGT's loads are served through Network Integration Transmission Service Agreements (NITSA) with other Transmission Providers. TSGT serves loads in the WECC Region primarily, within four (4) Balancing Authority Areas; WACM, PSCO, PNM, and PACE. The TSGT Transmission System, plus its' NITSA's, is adequate to deliver the TSGT Designated Network Resources to its' scattered member loads in a reliable manner. The major load serving regions of TSGT are typically separated by WECC Rated Interface Paths (Rated Paths), and the Total Transfer Capability (TTC) values have been determined under a methodology consistent with the *MOD-029-2a* Rated System Path Methodology.

3. TTC GENERAL METHODOLOGY

The TSGT TTC values for jointly owned paths (that are identified and rated through WECC processes and OTC determinations) are based upon the Rated System Path Methodology, found in *MOD-029-2a*. TSGT 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 utilizing actual flow levels at the combined path ratings and under simulated N-1 scenarios to ensure that the planning criterion is 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 Transmission Providers determine the appropriate combined TTC and the allocation to each path owner is based upon contractual capacity entitlements. This allocation is done outside of any WECC approval process since these paths are not part of an interface and do not impact any major recognized WECC Rated Paths.

If, during simulation to determine TTC in accordance with *MOD-029-2a,* a reliability limit is not identified, TSGT will base the TTC on the Thermal Facility Ratings for that studied segment. If the *MOD-029-2a* simulation studies result in sufficient flow on an ATC Path segment to determine a reliability limit, then the TTC on the ATC Path segment is set to that simulated reliability limit, while at the same time satisfying all planning criteria.

In addition, TSGT 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. TSGT will continue to determine the posted TTC and ATC for its extended paths using this approach.

4. CALCULATION OF ATC

4.1 ATC Calculation Intervals

TSGT utilizes the *MOD-029-2a* Rated System Path Methodology stated above to calculate ATC values. The ATC values are calculated for the following time frames:

Hourly values are calculated for the next **168 hours**
Daily values are calculated for the next **31 calendar days**
Monthly values are calculated for the next **12 months**

4.1.1 Methodology Used for ATC Calculation, per Intervals Defined in 4.1

4.1.1.1 ATC (Firm) in the Scheduling Horizon:

$ATCF=TTC - ETC_F - CBM – TRM + POSTBACKS_F + COUNTERFLOWS_F$ *

4.1.1.2 ATC (Firm) in the Operating Horizon:

$ATCF=TTC - ETC_F - CBM – TRM + POSTBACKS_F + COUNTERFLOWS_F$*

4.1.1.3 ATC (Firm) in the Planning Horizon:

$ATCF=TTC - ETC_F - CBM – TRM + POSTBACKS_F$

4.1.1.4 ATC (Non-Firm) in the Scheduling Horizon:

$ATCNF=TTC - ETC_F – ETC_{NF} - CBM – TRM + POSTBACKS + COUNTERFLOWS$

4.1.1.5 ATC (Non-Firm) in the Operating Horizon:

$ATCNF=TTC - ETC_F – ETC_{NF} - CBM – TRM + POSTBACKS + COUNTERFLOWS$

4.1.1.6 ATC (Non-Firm) in the Planning Horizon:

$ATCNF=TTC - ETC_F – ETCN_F - CBM – TRM + CERTAIN\ POSTBACKS$

* See definition of counterflow at the end of Section 4.2

4.2 Firm ATC Derivations

ATCF=TTC - ETCF - CBM – TRM + POSTBACKSF + COUNTERFLOWS$_F$*

Firm ATC is the amount of TTC that remains after the ETC$_F$, CBM, and TRM have been subtracted, and Postbacks$_F$ and Counterflows$_F$* have been added back in.

ETC$_F$ includes Firm Transmission Service Reservations (TSR) for serving Network Service Customers loads, Grandfathered Firm Transmission obligations, and any OATT Firm Transmission Sales. Some Firm ATC set-aside values have been created and are included for various paths to recognize system backup obligations and to handle unusual operating configurations when portions of the system become isolated from normal feeds. For the majority of the TSGT Path segments, the TTC is fully utilized for ETC and TRM components. One exception includes the Path segments associated with WECC Rated Path 30 (TOT1A), which connect to an adjacent Balancing Authority system where no TSGT Network Resources or Network Loads exist.

ETC$_F$ IS CALCULATED AS FOLLOWS:

$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F +$

NL$_F$ is the Firm Transmission Capacity set-aside to serve Peak, Native Load forecast commitments. TSGT does not have any Native Load, and as such, this value is set to zero (0).

NITS$_F$ is the Firm Transmission Capacity reserved for Network Integration Transmission Service (NITS) that is serving Designated Network Load. TSGT has represented all of its NITS obligations with a *Service Code* of NETWORK SERVICE and a *Service Type* of NETWORK. The amount of NITS reservation allocations for each path segment is determined by the delivery analysis of the Designated Network Resources available to serve Designated Network Loads, as constrained by the TTC of the TSGT paths that are available for delivery.

GF$_F$ represents those Firm Grandfathered (GF) agreements implemented prior to July 1996, under which TSGT has reserved capacity to serve transmission customers. TSGT currently has two GF agreements for which it has reserved

Firm capacity. Those agreements affect WECC Rated Path 31 (TOT 2A N>S), and individual TSGT Paths, NYUM > STY and STY>NYUM.

PTP_F represents the Confirmed, Firm TSR's with a *Service Code* of FIRM and a *Service Type* of POINT-TO-POINT.

ROR_F represents Confirmed, Yearly Firm TSR's that have an initial duration of 5-years or longer. Because of the initial duration, these Reservations qualify for Rollover Rights. Those Rollover Rights are represented in the ROR_F value.

CBM is <u>not</u> utilized by TSGT for any TSGT line segments, nor does TSGT maintain CBM for any of its Network Service Customers. As such, the value for CBM in the equation is always set to zero (0).

TRM is utilized by TSGT. FERC Order 890 Paragraph 273, notes the appropriate uses of TRM. Among the acceptable uses found in the above reference, TRM is allowed to be used for "automatic sharing of reserves". As such, TSGT utilizes TRM for the delivery and receipt of reserves associated with the Western Power Pool (WPP) and the Southwest Reserve Sharing Group (SRSG).

Postbacks of Firm Capacity include Firm TSR's that have been Annulled, Redirected (on a Firm basis), or have been subject to a Recall of the Transmission Capacity. Other Postbacks that can occur on the TSGT system would be associated with the Undesignation of a Designated Network Resource in order for the Network Customer to make a Firm sale to a third party. When these types of Undesignations occur, Firm Capacity equal to the amount of the Undesignation will be Recalled and made available through a Postback on a defined path that is connected to the Undesignated Network Resource.

Counterflows are the adjustments to capacity that increase the ATC in a counter direction to the prevailing TTC. **TSGT has no counterflows that are allowed to create Firm ATC in the opposite direction.**

The Scheduling, Operating, and Planning Horizons all use the same ATC Calculation formulas for Firm ATC. TSGT assumes that 100% of all Firm TSR's must be included in the ETC for the Firm ATC Calculations within all OASIS Horizons.

4.3 Non-Firm ATC Derivations:

ATCNF=TTC - ETCF – ETCNF- CBM – TRM + POSTBACKS + COUNTERFLOWS

TSGT uses the above Non-Firm ATC formula when determining the ATC for the Scheduling Horizon (next 8 hours, relative to the current hour) and the Operating Horizon (next 7 days, relative to the current day, beyond the Scheduling Horizon). However, the ATC Calculation for the Planning Horizon (all postings beyond the Operating Horizon) performs different Non-Firm ATC derivations than the Scheduling Horizon and Operating Horizon, as TSGT assumes that all Firm and Non-Firm TSR's will be fully utilized in the Planning Horizon. In addition, Counterflows and Postbacks for unscheduled TSR's are not included in the Planning Horizon.

In the ATC_{NF} Calculation, ETC_{NF} includes any Non-Firm TSR's made on the TSGT OASIS, plus any Grandfathered Non-Firm Transmission obligations. Some Non-Firm ATC Set-Aside amounts have been created and are included for various paths to recognize system backup obligations, in order to handle unusual operating configurations when portions of the system become isolated from normal feeds, and to comply with Path Operator requirements.

ETCNF IS CALCULATED AS FOLLOWS:

ETCNF = NITSNF + GFNF + PTPNF

$NITS_{NF}$ is the Non-Firm TSR's procured through the OASIS for Network Integration Transmission Service that is serving Designated Network Load, from an Undesignated Network Resource. TSGT offers Non-Firm Network Integrated Transmission Service with a *Service Code* of NETWORK NF with a *Service Type* of NETWORK. This service can be reserved only by Network Integration Transmission Service Customers, and the Confirmed TSR's are included in the $NITS_{NF}$ value.

GF_{NF} represents the Non-Firm Grandfathered (GF) agreements implemented prior to July 1996, under which TSGT has reserved capacity to serve Transmission Customers.

PTP_{NF} represents the Non-Firm, Confirmed TSR's that are procured through the OASIS with a *Service Code* of POINT-TO-POINT, and a *Service Type* of NON-FIRM.

CBM is not utilized by TSGT for any of the TSGT line segments and as such, the value for CBM in the equation is set to zero (0).

TRM is utilized by TSGT. FERC Order 890 Paragraph 273, notes the appropriate uses of TRM. Among the acceptable uses found in the above reference, TRM is allowed to be used for "automatic sharing of reserves". As such, TSGT utilizes TRM for the delivery and receipt of reserves associated with the Rocky Mountain Reserve Group (RMRG) and the Southwest Reserve Sharing Group (SRSG). TRM will reduce the utilized paths' Non-Firm ATC for all Horizons.

Postbacks for the Non-Firm ATC Calculation are accounted for in accordance with the NAESB Business Practice Standards. TSGT includes the full capacity amount of a Firm Transmission Service Reservation as a reduction to the Non-Firm ATC, and then implements a Postback of any unscheduled Firm capacity. The Postback of unscheduled Firm capacity is added back into the Non-Firm ATC Calculation as an increase to Non-Firm ATC, for both the Scheduling Horizon and Operating Horizon.

Counterflows (i.e. Counter Schedules) are allowed to positively increase the Non-Firm ATC for a path in the direction counter to the prevailing TTC rating. TSGT accounts for Confirmed Transmission Service Reservations, expected interchange, and internal Counterflows in the Firm and Non-Firm ATC Calculations in the following manner, relative to the use of Counterflows:

THE FOLLOWING FORMULAS ARE USED IN CALCULATING FIRM AND NON-FIRM ATC:

$ATC_F = TTC - ETC_F - CBM - TRM + POSTBACKS_F + COUNTERFLOWS_F$

$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM - TRM + POSTBACKS_{(F\ \&\ NF)} + COUNTERFLOWS_{(F\ \&\ NF)}$

Confirmed TSR's included in the ETC parameters by themselves do not contribute to Counterflow increases of the Non-Firm ATC in the counter direction unless they are scheduled. Schedules using both Firm and Non-Firm TSR's create Non-Firm ATC from Counterflows. These schedules are never allowed to create Firm ATC from Counterflows. Expected interchange for the Pre-Schedule period always requires the use of TSR's that are included in both Firm and Non-Firm ETC parameters. Interchange schedules for both Firm and Non-Firm TSR's are allowed to create Non-Firm ATC in the opposite path direction for the Scheduling Horizon and Operating Horizon. There is no difference in the way Counterflow adjustments to Non-Firm ATC are made for internal path boundaries. Counterflows are only included in the Non-Firm ATC Calculation. TSGT segments, and those for ATC Path segments that cross Balancing Authority Areas, allows all schedules associated with Confirmed Firm and Non-Firm TSR's to positively increase the Non-Firm ATC on the path in the counter direction to the scheduled direction. No schedules are ever allowed to create Firm ATC from Counterflows.

TSGT has fully implemented the FERC requirement for Counterflow treatment (as stated in FERC Order 890) for the creation of Non-Firm ATC in the counter direction. All schedules using both Firm and Non-Firm TSR's across all ATC Paths (including internal paths) create Non-Firm ATC in the counter direction. TSGT does not allow for the creation of Firm ATC from schedules in the counter direction due to the unpredictability of counter schedules and the potential degradation in service to Firm ETC users in the impacted direction.
Both, the Postbacks and Counterflow, calculations are performed whenever one of the TTC or ATC parameters change. The calculation is performed hourly, at minimum.

For the Planning Horizon, neither unscheduled use of Firm or Non-Firm TSR's is posted back to Non-Firm ATC, since TSGT's calculation always assumes that Firm and Non-Firm TSR's will be fully utilized beyond the Operating Horizon. Likewise, Counterflows do not impact Non-Firm ATC in the Planning Horizon due to the unpredictability of the counter schedules and the inability to submit schedules beyond the WECC Pre-Schedule period.

5. TRANSMISSION OPERATORS AND TRANSMISSION SERVICE PROVIDERS THAT PROVIDE TTC INFORMATION TO TSGT

5.1 TSGT receives TTC allocations on several jointly owned paths from the following path operators:

Western Area Power Administration (WACM)

- WECC Rated Paths 30, 31, 36, and 39

Western Area Power Administration (WALC)

- Common Bus line Shiprock 345kV to Four Corners 345kV

Public Service of New Mexico (PNM)

- WECC Rated Path 48
- Common Bus line San Juan 345kV to Shiprock 345kV
- Common Bus line San Juan 345kV to Four Corners 345kV

El Paso Electric Company (EPE)

- WECC Rated Path 47

6. TRANSMISSION OPERATORS AND TRANSMISSION SERVICE PROVIDERS THAT TSGT PROVIDES TTC INFORMATION TO

6.1 None

7. PATH-SPECIFIC ALLOCATION INFORMATION

7.1 WACM Paths 30, 31, 36, and 39:

WACM (Path Operator for WECC Rated Paths 30, 31, 36, and 39) continuously provides real-time TTC allocations based upon current operating conditions. TTC allocations are based on the studies run by WACM, and TTC values are allocated according to contractual agreements. With all lines in service, each of the following paths has an optimal, path-specific TSGT TTC allocation as follows:

7.1.1 Path 30: Maximum total TTC path rating of *650 MW*. Two TSGT line segments:

1. Craig to Bonanza 345kV= TSGT TTC of 29 MW
2. Craig to Calamity Ridge 138 kV (Craig/Hayden 138kV/Axial Basin/Meeker/Southwest Rangely 138kV)= TSGT TTC of 105 MW

7.1.2 Path 31: Maximum total TTC path rating of *690 MW:*

1. 1. Craig to San Juan 345kV= TSGT TTC of 135 MW N>S

2. 2. San Juan to Craig 345kV= TSGT TTC of 70 MW S>N

7.1.3 Path 36: Maximum total TTC path rating of *1680 MW:*

1. Path Gateway= Limits TTC to 461 MW
2. Laramie River Station to Ault= TSGT TTC of 322 MW if all Path 36 schedules are on this line
3. Laramie River Station to Story= TSGT TTC of 227 MW if all Path 36 schedules are on this line during outage of the Laramie River Station to Ault line

7.1.4 Path 39: Maximum total TTC path rating of *1680 MW* West to East. *1305 MW* East to West:

1. Path Gateway= Limits TSGT TTC to 260MW W>E and 210 MW E>W
2. Craig to Ault 345kV= TSGT TTC of 260 MW W>E and 150 MW E>W
3. Craig to Blue River 230kV= TSGT TTC of 110 MW W>E and 52 MW E>W

7.2 WALC Common Bus Line:

1. Shiprock 345kV to Four Corners 345kV= Total TTC line rating is 1200 MW. TSGT TTC allocation is 150 MW.

*Total TTC line ratings established at the thermal facility rating

7.3 PNM Common Bus Line:

1. San Juan 345kV to Shiprock 345kV= Total TTC line rating of 1075 MW. TSGT TTC allocation of 134 MW.
2. San Juan 345kV to Four Corners 345kV= Total TTC path rating of 1195 MW. TSGT TTC allocation of 149 MW.

*Total TTC line ratings established at the thermal facility rating

7.4 EPE Path 47 Southern New Mexico Import (SNMI):

EPE is the Path Operator for WECC Path 47 (SNMI), and the path allocations are shared between EPE, PNM, and TSGT.

7.4.1 Path 47. Maximum total TTC of 940 MW with all lines in service:

1. Belen/Bernardo/Socorro 115 kV= Total TTC path rating of 940MW. TSGT TTC of 75 MW N>S, 0 MW S>N

7.5 PNM Path 48: Northern New Mexico Import (NNMI)

PNM is the Path Operator for WECC Path 48 (NNMI). The TSGT rights on Path 48 are limited to serving TSGT Network Loads in Northern New Mexico, as well as some loads in Colorado. The TTC value that TSGT posts for Path 48 is determined from a Powerflow Study performed by PNM:

7.5.1 Path 48. Maximum total TTC path rating of 1849 MW with all lines in service:

1. Walsenburg to Gladstone 230kV with load serving TSGT= TTC of 207 MW N>S
2. Gladstone to Walsenburg 230kV with load serving TSGT= TTC of 207 MW S>N

7.6 Common Bus Agreement: SJ345 > Four Corners345

TSGT has Transmission Capacity Rights across two separate 345kV paths from San Juan to Four Corners

1. San Juan-Four Corners
2. San Juan-Shiprock-Four Corners.

TSGT receives a pro-rata TTC allocation for each of the two paths, based on contractual agreements.

7.7 Missouri Basin Power Project (MBPP)

TSGT is a participant in the Missouri Basin Power Project. TSGT receives capacity allocations on peripheral line segments associated with the MBPP and its' associated contracts. WACM is the Path Operator for the MBPP. TSGT receives TTC information from WACM and then determines TSGT's respective share of the TTC, based on contractual agreements. Participants are not allowed to post any Firm Transmission Capacity on the transmission lines that are part of the project. As such, TSGT does not post Firm Capacity on those paths that are part of the original MBPP agreement.

8. MINIMUM FREQUENCY OF RECALCULATION OF ATC

8.1 ATC is to be recalculated, at a minimum, in the following intervals, using the methodology selected:

Hourly values recalculate at least **once per hour**
Daily values recalculate at least **once per day**
Monthly values recalculate at least **once per day**

In addition, the TSGT Transmission System is configured as such that any impact that is defined as having an effect on the TTC value will trigger the recalculation of ATC for the impacted paths, at intervals more frequent than those defined for minimum recalculations. Whenever new information arrives that impacts an ATC Path, the system will recalculate ATC to ensure that the most current and accurate ATC values are posted. Also, Daily values will be determined based upon the minimum Hourly value within a day; Monthly values will be determined based upon the minimum Daily value within a month.

9. OUTAGE POSTING IMPACTS ON TTC/ATC FOR POSTED PATHS

9.1 Transmission outages and any impacting generator outages

Transmission outages and any impacting generator outages are entered into the OATI webTrans system as soon as notifications are provided by the TSGT Outage Coordinators, TSGT Real-Time System Operators, and jointly owned path operators. Generator outages do not impact the TTC values for any TSGT posted ATC Paths that aren't part of a jointly owned path. However, WACM (the Path Operator for several WECC Rated Paths which TSGT is a participant in) has determined through technical studies that a reduction in specific generation for WECC Path 31 and Path 36 will reduce the TTC for those paths. If the TTC for a jointly owned path is impacted by an outage, the TSGT TTC allocation will be determined and provided by the responsible path operator. The adjusted TTC values will be utilized in the ATC Calculation for all Transmission Services and time increments for the duration of the outage, on each impacted path. Based upon the outage information received, the magnitude and duration of impacts on the TTC of each bi-directional impacted path is determined prior to entry into the webTrans system. Once entered, the webTrans system will utilize the TTC values entered for the duration of the outage, and at such a time that the outage is no longer in effect, the webTrans system will revert back to using the TTC values normally set for that particular path.

9.2 If an outage will impact only a portion of a transmission service time period

If an outage will impact only a portion of a Transmission Service time period, then the TTC and ATC will be reduced for the entire Transmission Service time period to prevent over-scheduling of the impacted path. An outage record may be changed to extend an outage, terminate an outage, or update pertinent information within the outage posting. As soon as an action is taken on the outage record, the record is immediately updated to reflect the new TTC value and associated path ATC values. Outage information entered into webTrans is posted on the secure OATI OASIS website (via the software configuration between webTrans and webOASIS) and is accessible only by OATI OASIS users with digital certificates.

9.3 Transmission outages that cannot be mapped directly to the TSGT system model

Transmission outages that cannot be mapped directly to the TSGT system model but may have an impact on modeled paths on the system are evaluated by the transmission path operator to determine if a change in capacity is warranted due to the outage. If the outage results in a negative impact to a path that is a TSGT posted path, then the path operator will post the outage which will trigger a reduction in the TTC for the time period.

10. TSGT Total Transfer Capability (TTC) Summary Table

Attachment A is a summary table of the TSGT Bulk Electric System path segments that are included in TSGT posted ATC Paths, along with their associated TTC values.

11. Entities to be Notified Prior to Implementation of ATCID Changes

Attachment B includes the table of entities to be notified of ATCID changes.

12. ACRONYMS AND DEFINITIONS USED IN THIS DOCUMENT

BEPC – Basin Electric Power Cooperative
EPE – El Paso Electric Company
MBPP – Missouri Basin Power Project
NNMI – Northern New Mexico Imports
OASIS – Open Access Same-Time Information System
OATI – Open Access Technology International
PACE – PacifiCorp
PNM – Public Service Company of New Mexico
PSCO – Public Service Company of Colorado
SNMI – Southern New Mexico Imports
TSGT – Tri-State Generation and Transmission Association, Inc.
WACM – Western Area Power Administration - CM

WALC – Western Area Power Administration-DSE

WECC – Western Electric Coordinating Council

ATC (Available Transfer Capability)- A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.

CBM (Capacity Benefit Margin) - The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

Counterflow -A variable component of the Transmission Provider's selected ATC calculation methodology that impacts ATC in a direction counter to prevailing TTC rating.

ETC (Existing Transmission Commitments) - Committed uses of a Transmission Service Provider's Transmission system considered when determining ATC or AFC.

OTC (Operating Transfer Capability)- The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under current or projected operating conditions.

Postback -A variable component of the Transmission Provider's selected ATC calculation methodology that positively impacts ATC based on a change in status of a TSR or use of reserved capacity, or other conditions as specified by the Transmission Provider.

TRM (Transmission Reliability Margin) -The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

TTC (Total Transfer Capability) -The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TSGT is allocated a share of the TTC on Paths 30, 31, 36, 39, 47, and 48 and it is that allocated share that TSGT posts as its TTC on those Paths.

Tri-State Generation & Transmission Association, Inc.

Capacity Benefit Margin Implementation Document (CBMID) Statement

May 2020

Definition

Capacity Benefit Margin (CBM) is defined as the amount of firm transmission transfer capability preserved by the transmission provider for Purchasing-Selling Entity (PSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the PSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for a PSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the PSE only in times of emergency generation deficiencies.

Summary

TSGT's practice is to not maintain CBM.

Discussion

NERC Standard MOD-004-1 –Capacity Benefit Margin states the following in R1:

"The Transmission Service Provider that maintains CBM shall prepare and keep current a 'Capacity Benefit Margin Implementation Document' (CBMID) that includes, at a minimum, the following information…"

In Order 890A, paragraph 82, the FERC states, "The Commission clarifies in response to Duke that utilities do not need to make CBM available to LSEs on their system if the utilities do not reserve for themselves CBM or its equivalent. Comparability only requires transmission providers to make CBM available when they set aside for themselves transfer capability to meet generation reliability criteria.

Conclusion

Based on the FERC's allowance for Transmission Service Providers to not use CBM, TSGT's statement of CBM is as follows:

1. TSGT does not allow for the use of CBM and as such, its value is set to zero (0) in the ATC Calculation for all paths posted by TSGT.

2. TSGT's practice is to not maintain CBM.

3. TSGT will review its CBM practice, at least once every thirteen (13) months, and/or as required. TSGT will then post any and all changes to the OASIS.

Tri-State Generation & Transmission Association, Inc.

Transmission Reliability Margin Implementation Document (TRMID)

January 2023

1. PURPOSE

The Transmission Reliability Margin Implementation Document (TRMID) provides for the documentation of required information as specified in the NERC Standard MOD-008-1.

2. DEFINITION

The Transmission Reliability Margin (TRM) is the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

3. REQUIREMENTS

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

NAESB OASIS Standard 001-13.1.5 requires that a TRMID be posted under the ATC Information Link on the Transmission Provider's OASIS.

4. IMPLEMENTATION

4.1 Identification of Paths Allocated TRM

In FERC Order 890, FERC notes the acceptable uses of TRM, which include the use for automatic sharing of reserves. The allocation of TRM is further supported in MOD-008-1, as stated in R2 of the standard. Tri-State Generation and Transmission Association (TSGT) has allocated TRM for the use of automatic sharing of reserves and may change its policy regarding the use of TRM as needed.

4.1.1 Accommodate Transmission Service Requirements

To accommodate Transmission Service requirements for reserve sharing requirements, TSGT has allocated TRM on the paths shown in Table 1-A below. TSGT does not allocate capacity for TRM for any of the other uses of the transmission system as allowed in MOD-008-1, R1.1.

Table 1-A: List of TSGT Paths with TRM Allocated					
Reserve Sharing Group	**Allocated TRM Path**	**Scheduling POR**	**Scheduling POD**	**TRM MW**	**TSN #**
NWPP	LINC-BURL	LINC	BURL	25	LINCBURLNWPP
NWPP	BURL-NYUM	BURL	NYUM	25	BURLNYUMNWPP
NWPP	NYUM-STY	NYUM	STY	25	NYUMSTYNWPP
NWPP	STY-HNLK	STY	HNLK	27	STYHNLKNWPP-R1
NWPP	CRG-RFL	CRG	RFL	25	CRGRFLNWPP
NWPP	GHSE-HNLK	GHSE	HNLK	25	GHSEHNLKNWPP
NWPP	HNLK-HNLK	HNLK	HNLK	25	HNLKHNLKNWPP
NWPP	HNLK-STY	HNLK	STY	25	HNLKSTYNWPP
NWPP	LINC-LINC	LINC	LINC	50	LINCB2BNWPP
NWPP	BURL-BURL	BURL	BURL	50	BURLB2BNWPP
SRSG	PYGS-HIDALGO115	PYGS	PYGSGW	80	PYHDSRSG
		PYGSGW	HIDALGO115		

TSGT allocates TRM capacity for the delivery and receipt of reserves associated with the Northwest Power Pool (NWPP) and Southwest Reserve Sharing Group (SRSG). Transmission Service Numbers (TSNs) are created and managed by TSGT Operational Support personnel and decrement path Available Transfer Capability (ATC).

4.2 Calculation and TRM Allocation Methodology

TSGT works in conjunction with its Network Integration Transmission Service (NITS) Customers to utilize the sharing matrices. These matrices' are used by the respective reserve sharing groups to determine the megawatt amounts the customer is to provide in response to a contingency. The customer also determines which Designated Network Resources they will respond with. The response megawatt values are applied to accurately allocate TRM on TSGT's system.

4.2.1 Specific Calculation Derivation for TRM – NWPP and SRSG

The NWPP and SRSG obligations are primarily based upon the load levels of participants, rather than responding to the largest contingency in the group. As such, the reserve obligations can vary on an hourly basis. Based upon resource availability and production costs, the Tri-State Power Marketing (TSPM) determines how their reserve obligations will be met, delivered, and the points of delivery. Once TSPM determines how to respond, TSPM requests TSGT to model the chosen transmission path. In addition, TSPM requests TSGT to allow for the appropriate amount of TRM to deliver the reserve response.

4.2.2 Conditions Under Which the Transmission Provider Uses TRM

TSGT uses TRM to set aside capacity to deliver reserve obligations of its NITS customers. When the loss of a generation resource occurs (which resides within the reserve sharing group's footprint), the members of the reserve sharing group respond by delivering replacement energy to the deficient member. TRM is reserved to ensure sufficient transmission capacity exists to deliver the replacement energy requirement to the insufficient entity. A contingency can occur at any time, so TSGT does not release TRM for Non-Firm use to ensure its availability for reserve activations.

4.3 TRM Calculation Time Periods

Due to the nature of reserve activations, there is an inherent inconsistency surrounding events that would trigger activation. Because of this unpredictability, there is a need for transmission capacity to be available immediately; TSGT does not release unscheduled TRM for use as non-firm capacity. The calculations for all time periods decrease the ATC, for both firm and non-firm capacity.

4.3.1 Same-day and Real-time (Scheduling Horizon)

The Scheduling Horizon is defined as "a specified number of hours extending past the current hour". For the TSGT, the OASIS Scheduling Horizon is "equal to the current hour, plus an additional eight (8) hours". TRM is calculated utilizing the reserve group matrices, as described in Section 4.2. The TSGT does not recalculate the reserve sharing group requirements and obligations on a same-day and/or real-time basis as reserve activations cannot be forecasted. The full amount allocated for TRM use is deducted from the firm ATC calculation, on a same-day and real-time basis. Unscheduled TRM is not posted back to the ATC calculation for non-firm ATC.

4.3.2 Day-Ahead and Pre-Schedule (Operating Horizon)

The Operating Horizon is defined as "a specified number of hours extending past the end of the Scheduling Horizon". For TSGT, the OASIS Operating Horizon is "equal to the end of the Scheduling Horizon, plus an additional 168 hours".

TRM is calculated utilizing the reserve group matrices as described in Section 4.2. TSGT does not recalculate the reserve sharing group requirements and obligations on a day-ahead and/or pre-schedule basis as reserve activations cannot be forecasted. The full amount allocated for TRM use is deducted from the firm ATC calculation on a day-ahead and pre-schedule basis. Unscheduled TRM is not posted back to the ATC calculation for non-firm ATC.

4.3.3 Beyond Day-Ahead and Pre-Schedule (Planning Horizon)

The Planning Horizon is defined as "a specified number of days extending past the end of the Operating Horizon". For TSGT, the OASIS Planning Horizon is "equal to the end of the Operating Horizon, plus an additional 3650 days (10 years)". TRM is calculated utilizing the reserve group matrices as described in Section 4.2. TSGT does not recalculate the reserve sharing group requirements and obligations on a planning horizon basis, unless a change is made to the matrices. A change to the matrices must determine that the obligation or information is received from the respective reserve group and there are changes to the receipt and delivery points for future activations. The full amount allocated for TRM use is deducted from the firm ATC beyond the day-ahead and pre-schedule time frames. Unscheduled TRM is not posted back to the ATC calculation for non-firm ATC.

4.4 Demonstration of "No-Double Counting" of Contingency Outages When Performing CBM and TRM Calculations

As TSGT does not allocate for a Capacity Benefit Margin (CBM), and the value for CBM is set to zero (0) for all ATC calculation methodologies, TSGT does not include any components of CBM within the TRM capacity allocation.

4.5 Dissemination of TRM Allocation Information

TSGT will disseminate TRM allocation information in accordance with NERC MOD Standard 008-01 as requested and within 30 calendar days, as described in the Standard.

4.5.1 Written Request for Underlying Documentation

Upon the written request from a Transmission Service Provider, Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner, or Transmission Operator(s) for the underlying documentation that TSGT uses to determine TRM, TSGT will make the documentation available (if any) to any of the functions listed in MOD-008-1, R3. TSGT will follow the specified Data Request Procedures: DATA-002, to provide the requested data.

5. REVIEW OF TRM VALUES

5.1 Review of Calculated and Allocated TRM Values

TSGT will review its calculated and allocated values for TRM at least once every thirteen (13) months, and/or as required. TSGT will maintain a record of the assessment and any changes made.

6. NOTIFICATION OF TRM VALUES

6.1 Notification to Transmission Service Providers and Transmission Planner(s)

TSGT will notify the defined Transmission Service Providers and Transmission Planner(s) no more than seven (7) calendar days after a TRM value is initially established or is subsequently changed. The TRM values are always known by the TSGT Transmission Service Provider (TSP); the Transmission Operator (TOP) and TSP functions are administered by the same group within TSGT. Along with applicable information, TSGT will notify the following parties of any establishment or change to a TRM value:

Entity	Contact Information	Neighbor	TOP	TSP	TP	RC	PC(PA)
Tri-State Generation and Transmission Association, Inc.	Kevin Cloud, Senior OASIS/OATT Administrator 303.254.3284 kcloud@tristategt.org Ryan Hubbard, Transmission Planning Manager 303.254.3025 rhubbard@tristategt.org Sergio Banuelos Reliability Compliance Analyst 303.254.3231 ryawal@tristategt.org		X	X	X		

7. ACRONYMS AND DEFINITIONS USED IN THIS DOCUMENT

ATC- Available Transfer Capability**:** A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.

CBM -Capacity Benefit Margin**:** The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

FERC – Federal Energy Regulatory Commission

NAESB – North American Energy Standards Board

NERC- North American Electric Reliability Corporation

NITS- Network Integrated Transmission Service

NWPP – Northwest Power Pool (On February 8, 2022 NWPP changed its name to Western Power Pool.)

OASIS – Open Access Same Time Information System

SRSG – Southwest Reserve Sharing Group

TOP- Transmission Operator

TRM- Transmission Reliability Margin: The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

TRMID- Transmission Reliability Margin Implementation Document

TSGT – Tri-State Generation and Transmission Association

TSP – Transmission Service Provider

TSPM – Tri-State Power Marketing

Colorado Coordinated Planning Group
SLV Subcommitee

Wed, June 14, 2023
2:30 – 4:00 AM

Preliminary Phase 1 Results

Load Serving

Alternative	Description	Load Serving	Contingency
Base	Today's system	65 MW	SLV-Poncha (230kV)
1-3	115kV rebuilt to 230kV	183 MW	SLV-Poncha (230kV)
1-4	new 230kV (via Poncha Pass)	207 MW	New SLV-Poncha (230kV)
1-5	new double circuit 345kV (via Poncha Pass)	290 MW	New SLV-Poncha (345kV)
1-8	new 230kV (via CO114)	207 MW	New SLV-NewCO114 (230kV)

Generation Export

Alt	Description	Export (TTC)	Limiting Element	Contigency
Base	Today's system	93 MW	Sargent-Poncha 115kV	SLV-Poncha (230kV)
1-3	115kV rebuilt to 230kV	474 MW	SLV-Poncha 230kV	SLV-Poncha (230kV)
1-4	new 230kV (via Poncha Pass)	572 MW	SLV-Poncha 230kV, Sargent-Poncha 115kV	New SLV-Poncha (230kV)
1-5	new double circuit 345kV (via Poncha Pass)	1246 MW	Poncha-SLV (1) 345kV	New SLV-Poncha (345kV)
1-8	new 230kV (via CO114)	572 MW	SLV-Poncha 230kV, Sargent-Poncha 115kV	New SLV-NewCO114 (230kV)

Western Slope 2022 Study Report

Colorado Coordinated Planning Group

January 2023

Table of Contents

Executive Summary

This report was produced by the Colorado Coordinated Planning ("CCPG") Western Slope Subcommittee to study various proposals recommended to the subcommittee. The proposals and associated studies are meant to provide stakeholders information and insight on how changes to the Western Slope electric grid, whether that be a changing resource mix or potential transmission development, affect performance and reliability. The studies herein are meant to provide a high-level, coarse analysis and are not meant to supplant more refined analysis performed in studies such as a Large Generator Interconnection study or a WECC Path Rating process.

Four (4) proposals were studied by the Western Slope Subcommittee in 2022. The proposals were:

1. How does the retirement of Craig and Hayden powerplants affect WECC Rated Paths ("Path") TOT 1A, TOT 2A, TOT 3, and TOT 5 and general system performance if no additional generation is added to the Western Slope?
2. How does the retirement of Craig and Hayden powerplants, along with the unavailability of Western Slope hydropower generation due to a prolonged Western US drought affect Paths TOT 1A, TOT 2A, TOT 3, and TOT 5 and general system performance if no additional generation is added to the Western Slope?
3. To increase import and export capacity between Colorado's transmission system and Western Markets, what is the effect on Paths TOT 1A, TOT 2A, TOT 3, and TOT 5 and general system performance of a 500 kV line between Craig substation and PacifiCorp's Gateway South 500 kV line?
    a. This study assumes that Craig and Hayden powerplants are retired and 2,000 MW of new, dispersed generation is added along the Western Slope.
4. How does the retirement of Craig and Hayden powerplants affect Western Slope short-circuit levels?

Background

A theme to the proposals is how a changing Western Slope resource mix impacts Paths TOT 1A, TOT 2A, TOT 3, and TOT 5. Historically WECC Rated Paths have functioned to define transmission corridors meant to move large amount of power from generation to load centers. The intent is to preserve transfer capability for the Path owners who may have made long-term resource planning decisions based their ability to move power across the path. Changes to transmission topology which reduces a Path rating can undermine long-term resource planning. A summary of CCPG Paths and other import/export points (e.g. DC ties to Eastern Interconnection) are listed in **Table 1** and **Table 2** and shown visually in **Figure 1**.

Table 1: *CCPG (Colorado Region) Import/Export Paths*

WECC Rated Paths	Prevailing Direction		Non-Prevailing Direction	
TOT 1A: • Craig (M) – Bonanza 345 • Hayden (M) – Artesia 138 • Meeker – Rangely (M) 138	E → W	650 MW	W → E	Not Defined
TOT 2A: • San Juan (M) – Waterflow 345 • Shiprock (M) – Lost Canyon 230 • Hesperus – Glade Tap (M) 115 • SW Colorado Load Bubble	N → S	680 MW – SW CO Load	S → N	Not Defined
TOT 3: • LRS (M) – Ault 345 • Wayne Child (M) – Keota 345 • Archer (M) – Ault 230 • Terry Ranch Road (M) – Ault 230 • Cheyenne (M) – Owl Creek 115 • Sidney (M) – Spring Canyon 230 • Sidney (M) – Sterling 115	N → S	1835 MW	S → N	Not Defined
Other Paths	**Prevailing Direction**		**Non-Prevailing Direction**	
Gladstone Phase-shifting Transformer	N → S	40-190 MW	S → N	Not Defined
DC Ties: • Lamar DC Tie • Sidney DC Tie • Stegall DC Tie	W → E	• 210 • 200 • 100	E → W	• 210 • 200 • 100

Table 2: *Intraregional CCPG WECC Rated Paths*

WECC Path	Prevailing Direction		Non-Prevailing Direction	
TOT 5: • Ault – Craig (M) 345 • Terry Ranch Road (M) – N. Park 230 • Gore Pass (M) – Hayden East 230 • Gore Pass (M) – Hayden 138 • Curecanti (M) – Poncha 230 • Poncha (M) – N.Gunnison 115 • Malta – Basalt (M) 230 • Malta – Hopkins (M) 230	E → W	1680 MW	W → E	1353 MW
TOT 7: • Ault (M) – Fort St. Vrain 230 • Weld (M) – Fort St. Vrain 230 • Longs Peak – Fort St. Vrain (M) 230	N → S	890 MW	S → N	Not Defined

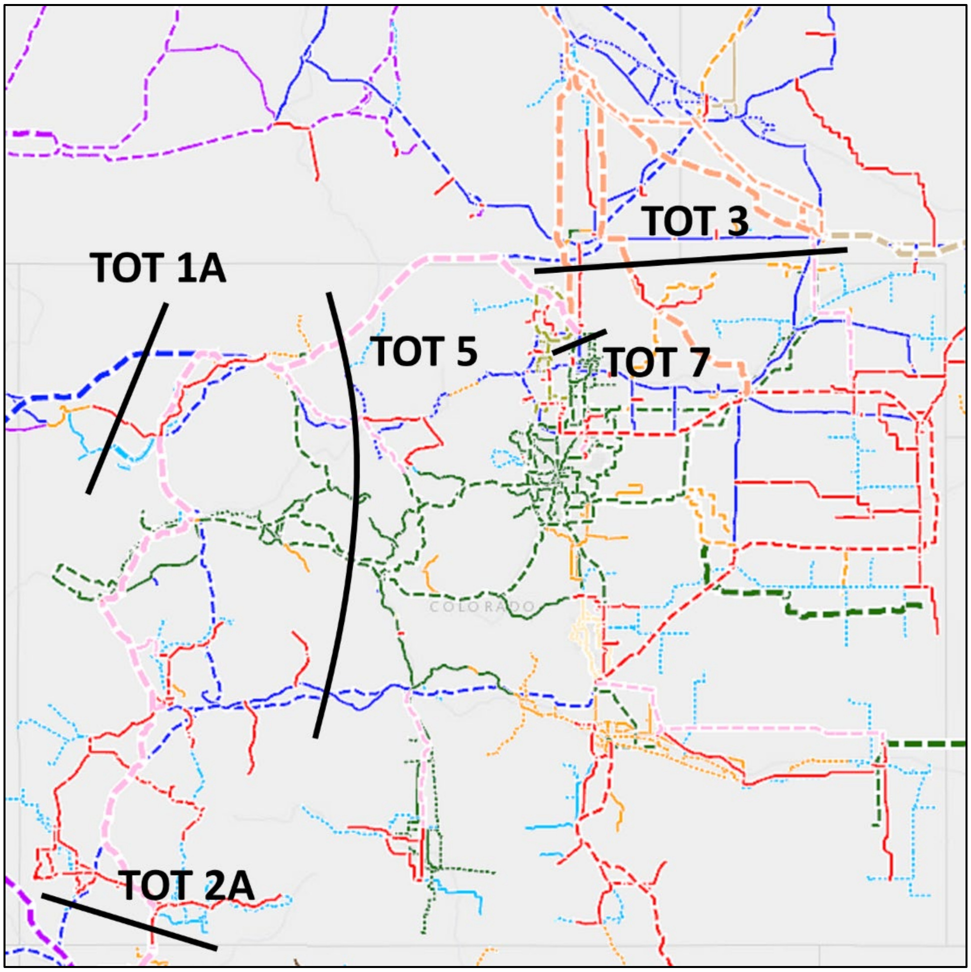


Figure 1: *Map of CCPG WECC Rated Paths*

Study 1 – WECC Path Impacts of Craig and Hayden Retirements

Objective

Craig and Hayden generation facilities have planned retirements through 2030. The retirements will occur over several years with Craig retiring units in 2025, 2028, and 2030 while Hayden will retire units in 2027 and 2028. The retirements of Craig and Hayden will create an approximately 1,900 MW deficit of generation in Colorado's Western Slope. While several generation projects have been announced (Axial Basin (145 MW), Dolores Canyon (110 MW), Garnet Mesa (80 MW)) the substantial deficit of generation will impact several regional Paths (TOT 1A, TOT 2A, TOT 3, TOT 5) until further generation resources are developed in the Western Slope.

The objective of Study 1 is to quantify the impacts of Craig and Hayden's retirement on the regions Paths assuming replacement generation does not develop until 2030 or later, after Craig and Hayden have retired. Based on Generator Interconnection queues, Western Slope generator interest skews heavily towards solar, these results are also reflective to how these Paths could operate during nighttime if minimal gas and BESS generation facilities are constructed.

Methodology

The study methodology for Study 1 will be a comparison of two cases with Craig and Hayden online and offline. In the offline case, make up generation will come from offline generation resources in eastern Colorado, the Front Range, and southeast Wyoming. The comparison will evaluate the N-0 change in TOT 1A, TOT 2A, TOT 3, and TOT 5 flows along with an evaluation of N-1 thermal overloads for each case.

Results

Prior to the retirement of Craig and Hayden, the Western Slope acts as a net-exporter of energy with TOT 1A, TOT 2A and TOT 5 moving energy to Utah, the Four Corners region, and the Front Range, respectively. After Craig and Hayden retire those paths reverse and the Western Slope becomes a net-importer of energy, **Table 3** and **Table 4, Figure 2** (left image, middle image).

No thermal overloads were identified under N-1 contingency analysis in either case, **Table 5**.

Table 3: *Colorado Western Slope N-0 WECC Rated Path Flows, 2032 Heavy Summer*

	2032 Heavy Summer (Baseline)		**2032 Heavy Summer (Craig and Hayden Retirements)**	
TOT 1A	E → W, Export	181.2 MW	W → E, Import	146.6 MW
TOT 2A	N → S, Export	134.6 MW	S → N, Import	91.2 MW
TOT 3	N → S, Import	729.2 MW	N → S, Import	1186.2 MW
TOT 5	W → E	500.1 MW	E → W	614.2 MW

Table 4: *Colorado Western Slope N-0 WECC Rated Path Flows, 2032 Heavy Winter*

	2032 Heavy Winter (Baseline)		**2032 Heavy Winter (Craig and Hayden Retirements)**	
TOT 1A	E → W, Export	278.3 MW	W → E, Import	14.6 MW
TOT 2A	N → S, Export	62.1 MW	S → N, Import	118.6 MW
TOT 3	N → S, Import	762.0 MW	N → S, Import	1107.9 MW
TOT 5	W → E	333.7 MW	E → W	874.6 MW

Table 5: *Colorado Western Slope N-1 Thermal Violations*

Element	Contingency	Rating	Baseline % Overload	Retirement % Overload
2032 Heavy Summer				
None	---			
2032 Heavy Winter				
None	---			

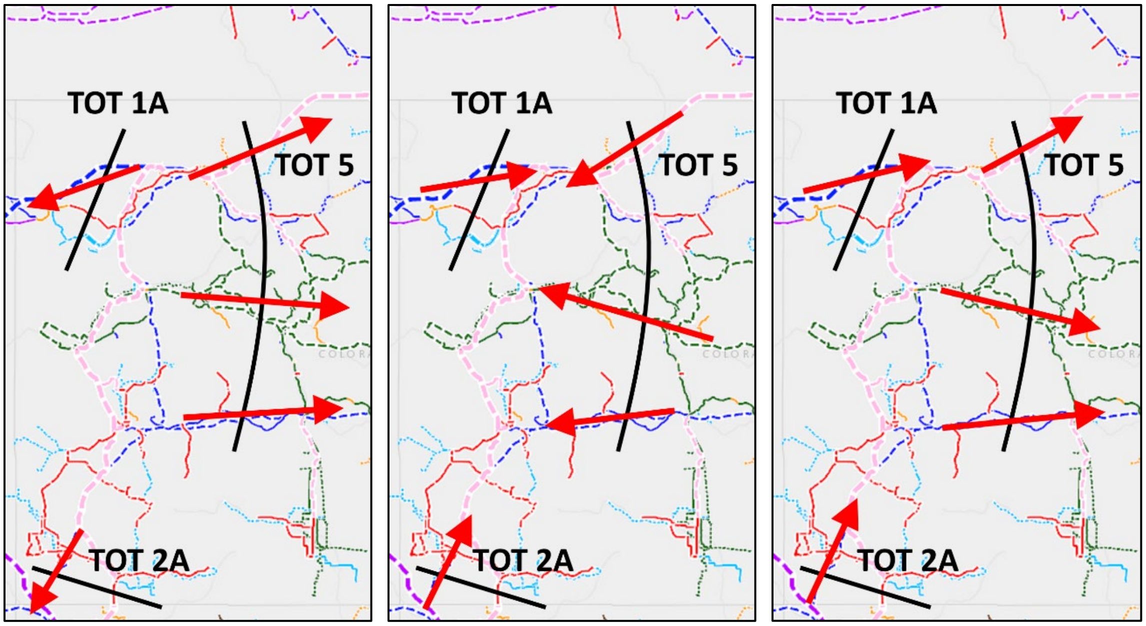


Figure 2: *Pre-Retirement Path Flows (left), Post-Retirement Path Flows (middle), Post-Retirement Path Flows Under Low Eastern Colorado Generation Availability (right)*

The inversion of TOT 1A, TOT 2A, and TOT 5 flows from the prevailing direction to the non-prevailing direction is not particularly significant due to no new performance violations; however, an operating condition where eastern Colorado and the Front Range have limited generation availability and high loads could be problematic.

TOT 3 and TOT 5 are the primary import paths to the Front Range and eastern Colorado load centers. The accepted WECC rating of both Paths sums to approximately 3,500 MW. But in the described operating condition, TOT 1A and TOT 2A, and the net load in the Western Slope determine how much power flows across TOT 5 to the Front Range, **Figure 2** (right image). Based on five (5) years of historical data, the maximum non-prevailing flows for TOT 1A and TOT 2A were 270 MW and 600 MW, respectively. Given approximately 900 MW of net load in the Western Slope, the actual TOT 5 flow value could be closer to 0 MW, resulting in an eastern Colorado and Front Range import limit being closer to 1,800 MW.

$$TOT\ 5_{MW} = TOT\ 1A_{MW} + TOT\ 2A_{MW} - Western\ Slope\ Net\ Load_{MW}$$

$$TOT\ 5_{MW} = 270\ MW + 600\ MW - 900\ MW$$

Table 6: *Colorado Western Slope N-0 WECC Rated Path Flows, 2032 Heavy Summer*

	2032 Heavy Summer (Baseline)		2032 Heavy Summer (Craig and Hayden Retirements w/ Low Eastern Colorado Generation)	
TOT 1A	E → W, Export	181.2 MW	W → E, Import	477.9 MW
TOT 2A	N → S, Export	134.6 MW	S → N, Import	433.4 MW
TOT 3	N → S, Import	729.2 MW	N → S, Import	1843.3 MW
TOT 5	E → W	500.1 MW	W → E	31.8 MW

In the 2032 Heavy Summer case, a cut plane east of TOT 5, south of TOT 3, and north of the Gladstone phase-shifting transformer will find the following case values:

- System Load: 11,700 MW
- System Nameplate Generation: 14,100 MW

There are sufficient resources to meet the load without needing to import any additional generation across TOT 3 or TOT 5. But when widespread weather and temperature phenomena are considered, the following values could be possible:

- System Nameplate Generation without Wind: 8,800 MW
- System Nameplate Generation without Wind and Solar/Storage: 5,900 MW

In both instances the required import to meet the load, 2,900 MW and 5,800 MW, would be beyond the combined import limit of 1,800 MW. The shortfall would require the use of Demand Side Management mitigations and potentially load shedding if the actual import deficit is large enough.

Study 2 – WECC Path Impacts Due to Prolonged US Drought and Coal Retirements

Objective

The prolonged Western US drought has raised concerns that lower reservoir water levels could impact the Federally owned hydropower generation fleet within the Colorado River Basin. Study 2 is an extension of Study 1 where the planned retirements of Craig and Hayden occur as planned and the Colorado River Basin hydropower generation units become inoperable due to low water levels, exacerbating the generation deficit within the Western Slope.

The objective of Study 2 is to quantify the impacts of Craig and Hayden's retirement and the loss of Western Slope hydropower generation (Blue Mesa, Morrow Point, Crystal, Flaming Gorge) on the regional Paths (TOT 1A, TOT 2A, TOT 3, TOT 5) assuming replacement generation does not develop until 2030 or later, after Craig and Hayden have retired.

Methodology

The study methodology for Study 2 will be a comparison of two cases with Craig, Hayden, and the Colorado River Basin hydropower generators online and offline. In the offline case, make up generation will come from offline generation resources in eastern Colorado, the Front Range, and southeast Wyoming. The comparison will evaluate the N-0 change in TOT 1A, TOT 2A, TOT 3, and TOT 5 flows along with an evaluation of N-1 thermal overloads for each case.

Results

The results of Study 2 mirror that of Study 1. The Western Slope Paths invert from their prevailing direction to the non-prevailing direction, **Table 7** and **Table 8**. The added loss of the Colorado River Basin hydropower units resulted in an increased net import across the Paths with both the 2032 Heavy Summer and 2032 Heavy Winter cases seeing an approximately 150 MW increase.

No thermal overloads were identified in either case, **Table 9**.

The operating condition described in Study 1 would also apply to Study 2, but the effects would be worse due to having even less generation available.

Table 7: *Colorado Western Slope N-0 WECC Rated Path Flows, 2032 Heavy Summer*

	2032 Heavy Summer (Baseline)		**2032 Heavy Summer (Craig and Hayden Retirements, Loss of Hydro)**	
TOT 1A	E → W, Export	181.2 MW	W → E, Import	113.3 MW
TOT 2A	N → S, Export	134.6 MW	S → N, Import	118.4 MW
TOT 3	N → S, Import	729.2 MW	N → S, Import	1143.3 MW
TOT 5	W → E	500.1 MW	E → W	749.8 MW

Table 8: *Colorado Western Slope N-0 WECC Rated Path Flows, 2032 Heavy Winter*

	2032 Heavy Winter (Baseline)		**2032 Heavy Winter (Craig and Hayden Retirements, Loss of Hydro)**	
TOT 1A	E → W, Export	278.3 MW	E → W, Import	15.9 MW
TOT 2A	N → S, Export	62.1 MW	S → N, Import	150.6 MW
TOT 3	N → S, Import	762.0 MW	N → S, Import	1071.88 MW
TOT 5	E → W	333.7 MW	W → E	1000.9 MW

Table 9: *Colorado Western Slope N-1 Thermal Violations*

Element	Contingency	Rating	Baseline % Overload	Retirement % Overload
2032 Heavy Summer				
None	---			
2032 Heavy Winter				
None	---			

Study 3 – Increasing CCPG and Western Markets Transfer Capacity

Objective

In the wake of Winter Storm Uri, resource adequacy and access to those resources has become a focal point at FERC, NERC, and other organizations. The state of Colorado has relatively limited connectivity to the larger WECC system with import/export paths consisting of TOT 1A, TOT 2A, TOT 3, Gladstone phase-shifting transformer and the DC tie at Lamar (Sidney and Stegall DC ties are inherently part of

TOT 3). This limited connectivity dampens the ability to export excess power in support of reliability elsewhere in the interconnection or import enough power if the state faced significant shortfalls.

The objective of Study 3 is to quantify the performance of a 500 kV connection between PacifiCorp's Gateway South 500 kV line and Craig substation.

Methodology

The study methodology used for this analysis was an iterative injection group N-1 contingency analysis and was performed on the 2032 Heavy Summer, 2032 Heavy Winter, and 2033 Light Spring cases. Two injection groups were defined, a set of 'source' generators and a set of 'sink' generators. The iterative process increases the output of the source generators by a set amount while reducing the output of the sink generators by an equivalent amount. The spatial location of the source and sink injection groups are selected to stress the transfer limits of TOT 1A, TOT 2A, TOT 3 and the 500 kV line. After the generation dispatch for both source and sink injection groups is set, a full N-1 contingency analysis is performed. This process repeats until the source generators achieve their maximum power output – this value is case and import/export dependent and ranged from 3,500 MW to 5,000 MW.

In each of the cases Craig and Hayden powerplants were retired and 2,000 MW of fuel-type agnostic replacement generation was added to the following locations:

1. Craig 345 kV Bus, 750 MW
2. Hayden 230 kV Bus, 250 MW
3. Montrose 345 kV Bus, 250 MW
4. Grand Junction 230 kV Bus, 350 MW
5. Rifle 230 kV Bus, 250 MW
6. Hesperus 115 kV Bus, 150 MW

It is widely understood that as Craig and Hayden retire replacement generation will be developed in the Western Slope but if the replacement generation was placed back at Craig and Hayden the results would be similar to if Craig and Hayden never retired, which would not provide any additional insight into generation development. The dispersed generation achieves a stakeholder task of providing a 'proof of concept' that multiple Point of Interconnections ("POI") exist for new generation while not negatively impacting Western Slope transmission system.

Xcel's "Colorado Power Pathway" and Tri-State's "Responsible Energy Plan" transmission projects were included in the cases and 3,000 MW of fictitious generation was added to the following locations:

1. Tundra 345 kV Bus, 500 MW
2. May Valley 345 kV Bus, 1,000 MW
3. Goose Creek 345 kV Bus, 1,000 MW
4. Lamar 230 kV Bus, 100 MW
5. Big Sandy 230 kV Bus, 400 MW

The analysis will be performed on a case without the 500 kV and repeated on a case with the 500 kV line.

CCPG Footprint to Western Markets (Export)

When exporting from Colorado the source generators are the 5,000 MW of added generation (2,000 MW of dispersed Western Slope generation and 3,000 MW of CPP and REP generation). The sink generators are in Western Wyoming and Central Utah (Jim Bridger, Huntington, Hunter, Currant Creek, etc). The sink generators were selected to stress the export capability of the 500 kV in the direction of Utah and Western Wyoming.

Fictitious generators are used as the source generators as existing generators are already committed to load within the case and generally there is not enough available capacity the existing generation fleet for the export levels needed to be studied. Sink generators are always existing generators.

Results

A summary of the each Path flow and a summation of the total export at each iterative injection level is shown in **Table 10**, **Table 11**, and **Table 12**. Each Path may have a series of colored cells. If a cell is colored "ORANGE" that indicates that the Path flow value is either near the Paths accepted limit or flowing in the non-prevailing direction and the accepted rating is not defined. If the cell is colored "RED" that indicates that the Path flow is beyond the accepted Path limit. Ideally, the export capacity limit would occur when the first Path is operating at its accepted limit.

Without the 500 kV line, TOT 1A and TOT 2A (and to a lesser extent TOT 3) define the export capability out of the Western Slope. The 500 kV line provides additional capability to export from the Western Slope by the limit comes from the inability to move sufficient power from Eastern Colorado to the Western Slope without first violating TOT 5 accepted rating. As a result, the net export capability is not significantly different with or without the 500 kV line.

Thermal overloads were identified and can be categorized into two (2) groups: Denver Metro overloads and Path overloads (predominately TOT 5 elements). The thermal overload tables are available as an attachment to this report.

The Denver Metro overloads have been discussed in previous studies (CCPG 80x30 Task Force, CCPG Responsible Energy Plan Task Force, CCPG Lamar Front Range Task Force). In the Colorado export scenario, the excess generation in eastern Colorado is moved out of state via TOT 1A, TOT 2A, TOT 3, and the 500 kV line (if modeled). But to get to those export Paths requires moving power from eastern Colorado across TOT 5 which places the Denver Metro transmission system in the middle of those two. These overloads may need to be addressed in the future but are beyond the scope of this study.

The Path overloads observed were typical of violations seen today due to high Path transfers. The overloads tended to be lower voltage lines with lower thermal ratings when a parallel higher voltage line is opened as a contingency. When these results are seen in an operational timeframe, the overloaded element is opened as a pre-contingent mitigation. TOT 5 for instance has several elements that need to be opened or reconfigured (e.g. Canon West 230 kV ring bus, Mary's Lake transformer, etc.) to achieve the accepted rating. Beyond those overloads which can be mitigated operationally, the next set of Path overloads are the Path elements themselves. Unless there is an intent to increase those ratings, the Path rating will dictate the export capability. Those limits are highlighted in the "RED" cells in **Table 10**, **Table 11**, and **Table 12**.

Table 10: *2032 Heavy Summer Colorado Export to Western Markets, Baseline (left) and with 500 kV Tie-Line (right)*

2032 Heavy Summer (Baseline)								
Injection	**TOT2A**	**Gladstone PST**	**TOT1A**	**TOT3**	**500 kV Line**	**DC Ties**	**TOT5**	**Total Export**
0	93	25	-32	644	0	-245	-719	-313
250	156	34	32	553	0	-245	-766	-86
500	219	43	96	462	0	-245	-812	141
750	281	52	159	372	0	-245	-857	365
1000	342	62	222	281	0	-245	-902	590
1250	401	71	284	189	0	-245	-945	812
1500	461	81	346	98	0	-245	-987	1035
1750	520	91	408	8	0	-245	-1030	1256
2000	578	100	469	-82	0	-245	-1072	1474
2250	637	110	525	-174	0	-245	-1110	1691
2500	694	121	583	-265	0	-245	-1147	1908
2750	750	131	640	-356	0	-245	-1184	2122
3000	805	141	701	-445	0	-245	-1225	2337
3250	863	152	746	-542	0	-245	-1252	2548
3500	Diverged							
3750	Diverged							
4000	Diverged							
4250	Diverged							
4500	Diverged							
4750	Diverged							
5000	Diverged							

2032 Heavy Summer (w/ 500 kV Line)								
Injection	**TOT2A**	**Gladstone PST**	**TOT1A**	**TOT3**	**500 kV Line**	**DC Ties**	**TOT5**	**Total Export**
0	77	23	-58	661	68	-245	-740	-306
250	116	30	-38	596	176	-245	-819	-67
500	151	37	-17	531	287	-245	-898	172
750	187	44	4	466	395	-245	-975	409
1000	223	51	25	402	503	-245	-1052	645
1250	259	58	45	337	611	-245	-1128	881
1500	294	65	66	272	718	-245	-1203	1116
1750	329	72	86	208	824	-245	-1278	1348
2000	363	79	106	143	929	-245	-1350	1579
2250	397	86	127	78	1033	-245	-1422	1810
2500	431	93	148	14	1137	-245	-1494	2040
2750	464	101	168	-50	1239	-245	-1564	2267
3000	497	108	189	-116	1339	-245	-1632	2494
3250	530	115	210	-181	1439	-245	-1701	2720
3500	552	122	232	-250	1543	-245	-1764	2944
3750	587	130	252	-319	1632	-245	-1824	3165
4000	624	139	271	-389	1718	-245	-1882	3386
4250	Diverged							
4500	686	156	311	-525	1895	-245	-1995	3818
4750	Diverged							
5000	Diverged							

Table 11: *2032 Heavy Winter Colorado Export to Western Markets, Baseline (left) and with 500 kV Tie-Line (right)*

2032 Heavy Winter (Baseline)								
Injection	**TOT2A**	**Gladstone PST**	**TOT1A**	**TOT3**	**500 kV Line**	**DC Ties**	**TOT5**	**Total Export**
0	-61	26	34	640	0	-95	-997	-546
250	-2	35	100	547	0	-95	-1042	-319
500	55	43	166	455	0	-95	-1087	-96
750	112	52	232	363	0	-95	-1132	128
1000	168	61	298	270	0	-95	-1175	352
1250	224	70	363	178	0	-95	-1218	574
1500	280	79	428	87	0	-95	-1261	795
1750	318	85	501	-13	0	-95	-1298	1012
2000	374	95	563	-104	0	-95	-1338	1231
2250	432	104	621	-196	0	-95	-1377	1448
2500	488	113	685	-284	0	-95	-1420	1665
2750	548	124	739	-374	0	-95	-1458	1880
3000	609	134	796	-462	0	-95	-1499	2096
3250	Diverged							
3500	Diverged							
3750	Diverged							
4000	Diverged							
4250	Diverged							
4500	Diverged							
4750	Diverged							
5000	Diverged							

2032 Heavy Winter (w/ 500 kV Line)								
Injection	**TOT2A**	**Gladstone PST**	**TOT1A**	**TOT3**	**500 kV Line**	**DC Ties**	**TOT5**	**Total Export**
0	-93	23	-20	673	135	-95	-1038	-533
250	-59	30	9	603	232	-95	-1111	-296
500	-25	36	37	533	327	-95	-1183	-63
750	9	43	66	464	422	-95	-1255	171
1000	43	50	94	395	518	-95	-1327	405
1250	76	56	123	325	612	-95	-1398	637
1500	109	63	151	256	705	-95	-1468	867
1750	122	67	182	183	812	-95	-1536	1095
2000	157	74	210	113	901	-95	-1603	1324
2250	192	81	238	45	990	-95	-1670	1551
2500	227	89	266	-22	1079	-95	-1739	1778
2750	265	97	290	-88	1170	-95	-1806	2005
3000	303	105	310	-156	1261	-95	-1870	2230
3250	335	112	332	-217	1365	-95	-1943	2456
3500	370	120	352	-285	1454	-95	-2002	2676
3750	404	128	369	-354	1549	-95	-2062	2899
4000	424	134	462	-409	1570	-95	-2137	3094
4250	453	139	475	-499	1656	-95	-2177	3317
4500	Diverged							
4750	Diverged							
5000	Diverged							

Table 12: *2033 Light Spring Colorado Export to Western Markets, Baseline (left) and with 500 kV Tie-Line (right)*

2033 Light Spring (Baseline)								
Injection	**TOT2A**	**Gladstone PST**	**TOT1A**	**TOT3**	**500 kV Line**	**DC Ties**	**TOT5**	**Total Export**
0	-295	55	21	727	0	50	-297	-996
250	-233	64	82	627	0	50	-336	-764
500	-172	73	142	528	0	50	-374	-535
750	-111	82	202	428	0	50	-412	-305
1000	-62	89	257	312	0	50	-433	-78
1250	-1	99	315	214	0	50	-469	149
1500	61	108	374	119	0	50	-509	374
1750	124	118	434	26	0	50	-550	600
2000	188	128	493	-65	0	50	-593	824
2250	251	138	552	-155	0	50	-635	1046
2500	316	148	608	-247	0	50	-675	1269
2750	379	157	653	-350	0	50	-700	1489
3000	451	167	699	-443	0	50	-735	1710
3250	517	177	748	-536	0	50	-770	1928
3500	557	184	828	-610	0	50	-829	2129
3750	Diverged							
4000	Diverged							
4250	Diverged							
4500	Diverged							
4750	Diverged							
5000	Diverged							

2033 Light Spring (w/ 500 kV Line)								
Injection	**TOT2A**	**Gladstone PST**	**TOT1A**	**TOT3**	**500 kV Line**	**DC Ties**	**TOT5**	**Total Export**
0	-349	50	-61	780	217	50	-364	-973
250	-309	57	-32	701	300	50	-429	-735
500	-268	64	-3	622	382	50	-493	-497
750	-227	71	26	543	463	50	-556	-260
1000	-197	77	53	447	540	50	-602	-24
1250	-156	84	82	369	620	50	-665	211
1500	-114	92	111	294	701	50	-731	446
1750	-70	100	141	222	781	50	-798	680
2000	-26	108	171	151	862	50	-866	914
2250	18	116	201	81	942	50	-934	1146
2500	63	124	228	11	1022	50	-1000	1376
2750	104	131	247	-70	1105	50	-1055	1607
3000	153	140	268	-141	1188	50	-1118	1840
3250	194	148	291	-212	1273	50	-1181	2068
3500	212	153	388	-269	1298	50	-1262	2270
3750	263	162	411	-338	1373	50	-1323	2497
4000	288	166	421	-455	1443	50	-1336	2723
4250	318	171	435	-559	1514	50	-1361	2947
4500	365	179	456	-626	1592	50	-1421	3168
4750	426	190	475	-687	1660	50	-1483	3388
5000	Diverged							

Western Markets to CCPG Footprint (Import)

When importing from Western Markets the source generators were 3,000 MW of fictitious generation added at Jim Bridger, Aeolus, and near Salt Lake City. The sink generators are in Eastern Colorado and the Front Range (Missile Site, Pawnee, St. Vrain, etc). The sink generators were selected to stress the import capability of the 500 kV in the direction of the Western Slope and the Front Range.

Fictitious generators are used as the source generators as existing generators are already committed to load within the case and generally there is not enough available capacity the existing generation fleet for the import levels needed to be studied. Sink generators are always existing generators.

Results

A summary of the each Path flow and a summation of the total import at each iterative injection level is shown in **Table 13**, **Table 14**, and **Table 15**. Each Path may have a series of colored cells. If a cell is colored "ORANGE" that indicates that the Path flow value is either near the Paths accepted limit or flowing in the non-prevailing direction and the accepted rating is not defined. If the cell is colored "RED" that indicates that the Path flow is beyond the accepted Path limit. Ideally, the export capacity limit would occur when the first Path is operating at its accepted limit.

Without the 500 kV line, TOT 1A and TOT 2A (and to a lesser extent TOT 3) define the export capability out of the Western Slope. The 500 kV line provides additional capability to export from the Western Slope buta the limit comes from the inability to move sufficient power from Eastern Colorado to the Western Slope without first violating TOT 5 accepted rating. As a result, the net export capability is not significantly different with or without the 500 kV line.

Thermal overloads were identified and were predominately associated with TOT 3 and TOT 5 elements and to a lesser extent TOT 1A. The thermal overload tables are available as an attachment to this report.

The Path overloads observed, are again, typical of violations seen today due to high Path transfers. For TOT 3, the overloads appear north and south of the Path. For TOT 5, the overloads occur along the northern most transmission lines out of Hayden. And for TOT 1A, the underlying 138 kV system between Hayden and Vernal. The overloads again tend to be lower voltage lines with lower thermal ratings when a parallel higher voltage line is opened as a contingency. Unless there is an intent to increase those ratings, the Path rating will dictate the import capability. Those limits are highlighted in the "RED" cells in **Table 13**, **Table 14**, and **Table 15**.

Table 13: *2032 Heavy Summer Western Markets Import to Colorado, Baseline (left) and with 500 kV Tie-Line (right)*

2032 Heavy Summer (Baseline)								
Injection	**TOT2A**	**Gladstone PST**	**TOT1A**	**TOT3**	**500 kV Line**	**DC Ties**	**TOT5**	**Total Import**
0	93	25	-32	644	0	-245	-719	313
250	47	14	-85	773	0	-245	-604	552
500	0	3	-142	896	0	-245	-481	790
750	-51	-8	-200	1018	0	-245	-354	1032
1000	-103	-20	-259	1140	0	-245	-226	1277
1250	-165	-33	-323	1276	0	-245	-83	1552
1500	-237	-45	-392	1417	0	-245	76	1846
1750	-297	-56	-451	1538	0	-245	210	2097
2000	-389	-71	-529	1710	0	-245	397	2454
2250	-415	-76	-562	1776	0	-245	465	2584
2500	-489	-85	-622	1893	0	-245	609	2844
2750	Diverge							
3000	Diverge							

2032 Heavy Summer (w/ 500 kV Line)								
Injection	**TOT2A**	**Gladstone PST**	**TOT1A**	**TOT3**	**500 kV Line**	**DC Ties**	**TOT5**	**Total Import**
0	77	23	-58	661	68	-245	-740	306
250	54	15	-74	766	-28	-245	-595	554
500	30	5	-92	865	-127	-245	-443	804
750	5	-4	-110	963	-232	-245	-286	1059
1000	-21	-13	-128	1061	-336	-245	-127	1314
1250	-54	-23	-148	1170	-450	-245	50	1600
1500	-92	-34	-170	1283	-574	-245	244	1908
1750	-124	-43	-188	1380	-681	-245	409	2171
2000	-175	-56	-214	1519	-821	-245	636	2540
2250	-183	-60	-224	1572	-886	-245	722	2680
2500	-216	-69	-243	1673	-990	-245	884	2946
2750	-257	-78	-262	1791	-1096	-245	1056	3239
3000	Diverge							

Table 14: *2032 Heavy Winter Western Markets Import to Colorado, Baseline (left) and with 500 kV Tie-Line (right)*

2032 Heavy Winter (Baseline)								
Injection	**TOT2A**	**Gladstone PST**	**TOT1A**	**TOT3**	**500 kV Line**	**DC Ties**	**TOT5**	**Total Import**
0	-64	25	31	647	0	-95	-990	560
250	-105	15	-19	778	0	-95	-883	792
500	-149	5	-73	902	0	-95	-768	1024
750	-197	-5	-129	1023	0	-95	-648	1259
1000	-246	-15	-186	1145	0	-95	-526	1497
1250	-296	-27	-243	1267	0	-95	-403	1738
1500	-360	-39	-310	1410	0	-95	-254	2024
1750	-430	-52	-380	1557	0	-95	-96	2324
2000	-478	-60	-433	1653	0	-95	18	2529
2250	-536	-69	-489	1790	0	-95	145	2789
2500	-586	-77	-543	1897	0	-95	262	3008
2750	-667	-84	-610	2030	0	-95	423	3296
3000	-656	-83	-616	2035	0	-95	419	3295

2032 Heavy Winter (w/ 500 kV Line)								
Injection	**TOT2A**	**Gladstone PST**	**TOT1A**	**TOT3**	**500 kV Line**	**DC Ties**	**TOT5**	**Total Import**
0	-95	22	-21	679	130	-95	-1029	548
250	-115	14	-35	786	40	-95	-894	787
500	-137	6	-52	888	-54	-95	-751	1030
750	-159	-2	-69	986	-152	-95	-603	1273
1000	-183	-11	-87	1084	-252	-95	-451	1522
1250	-208	-19	-105	1183	-353	-95	-298	1773
1500	-242	-30	-127	1299	-470	-95	-116	2073
1750	-280	-41	-149	1418	-593	-95	78	2386
2000	-301	-47	-164	1501	-680	-95	209	2598
2250	-332	-55	-183	1608	-786	-95	372	2869
2500	-360	-62	-201	1688	-885	-95	523	3101
2750	-394	-70	-222	1806	-998	-95	699	3395
3000	-376	-68	-222	1816	-1006	-95	690	3393

Table 15: *2033 Light Spring Western Markets Import to Colorado, Baseline (left) and with 500 kV Tie-Line (right)*

2033 Light Spring (Baseline)								
Injection	**TOT2A**	**Gladstone PST**	**TOT1A**	**TOT3**	**500 kV Line**	**DC Ties**	**TOT5**	**Total Import**
0	-332	44	-8	818	0	50	-223	1164
250	-376	33	-58	938	0	50	-116	1389
500	-423	22	-111	1053	0	50	-3	1615
750	-470	11	-164	1166	0	50	109	1839
1000	-535	-4	-233	1310	0	50	258	2132
1250	-577	-13	-282	1412	0	50	360	2334
1500	-661	-30	-362	1584	0	50	539	2687
1750	-679	-34	-392	1643	0	50	594	2798
2000	-740	-46	-456	1774	0	50	730	3066
2250	-726	-45	-462	1782	0	50	725	3065
2500	-712	-42	-468	1788	0	50	721	3060
2750	Diverge							
3000	Diverge							

2033 Light Spring (w/ 500 kV Line)								
Injection	**TOT2A**	**Gladstone PST**	**TOT1A**	**TOT3**	**500 kV Line**	**DC Ties**	**TOT5**	**Total Import**
0	-376	39	-73	859	170	50	-275	1149
250	-396	31	-89	957	79	50	-140	1382
500	-421	22	-107	1050	-11	50	1	1617
750	-444	14	-125	1141	-101	50	141	1847
1000	-481	1	-149	1258	-216	50	325	2153
1250	-501	-6	-165	1340	-300	50	452	2362
1500	-550	-21	-194	1480	-435	50	673	2730
1750	-553	-23	-204	1527	-488	50	742	2845
2000	-588	-33	-226	1637	-597	50	914	3131
2250	-570	-31	-227	1640	-611	50	914	3129
2500	-552	-29	-227	1643	-626	50	913	3127
2750	Diverge							
3000	-513	-24	-228	1650	-657	50	911	3122

Study 4 – Change is System Short-Circuit Strength Post-Coal Retirements

Objective

Sufficient short circuit current is a critical component to detecting system faults and correctly operating breakers to isolate the faulted condition. Synchronous generators have played a key role in protection systems as they are an excellent source of fault current during system faults. With the announced retirements of Craig and Hayden generating facilities, Colorado's Western Slope transmission system is losing its two largest sources of fault current.

The objective of this portion of the report is to tabulate the short-circuit MVA (SC_{MVA}) between two WECC planning cases, one representing today's system with Craig and Hayden online and one representing a future system where Craig and Hayden have been retired.

Methodology

The SC_{MVA} will be calculated using Siemens PSS/E built-in IEC 60909 Fault Calculator. The IEC 60909 fault calculation provides an approximate value of fault current that can be expected in a given transmission system. The results of the IEC 60909 fault calculation have been previously benchmarked against ASPEN OneLiner™ and have provided similar results.

The WECC approved 2023 Heavy Summer (23HS1) was used as the online benchmark case. The offline comparison case was the 2032 Heavy Summer case built for the Western Slope 2022 study year.

Results

There was a relatively small decrease in SC_{MVA} strength across the Western Slope transmission system. Large decreases were observed at Craig and Hayden.

Table 16: *Change in Short-Circuit MVA Due to Craig and Hayden Retirements*

Bus Number	Bus Name	2023 Heavy Summer, 3LG SC_{MVA} (PU)	2032 Heavy Summer, 3LG SC_{MVA} (PU)	ΔSC_{MVA}
70088	Gore Pass	28.84	26.02	-2.82
79142	Hayden East	66.23	39.61	-26.62
79039	Hayden West	66.23	39.59	-26.64
79014	Craig 345	87.81	49.56	-38.25
79013	Craig 230	89.88	45.84	-44.04
65193	Bonanza	46.28	42.86	-3.42
79266	Meeker	46.93	37.47	-9.46
79058	Rifle	45.21	40.37	-4.84
79036	Grand Junction	33.15	31.44	-1.71
79049	Montrose	30.73	29.65	-1.08
79072	Hesperus	37.05	34.94	-2.11
79045	Lost Canyon	18.84	19.03	0.19
79021	Curecanti	26.92	26.70	-0.22

70309	Parachute	30.75	29.88	-0.87
70438	Uintah	18.33	18.06	-0.27
70233	Horizon	18.96	18.67	-0.29

Appendix A

Table 17: Voltage Criteria

Voltage Criteria for Steady State Power Flow Analysis		
Conditions	**Operating Voltages**	**Delta-V**
Normal (P0 Event)	0.95 - 1.05	N/A
Contingency (P1 Event)	0.90 - 1.10	8%
Contingency (P1 Event)	0.92 – 1.10 (PRPA Only)	8%
Contingency (P2-P7 Event)	0.90 - 1.10	None

Table 18: Thermal Loading Criteria

Equipment Loading Criteria		
System Condition	**Maximum Loading[1] (Percent of Continuous Rating)**	
	Transmission Lines	**Other Facilities**
Normal (P0 event)	80/100	100
Contingency (P1-P7 event)	100	100

[1] The continuous rating is synonymous with the static thermal rating. Facilities exceeding 80% criteria will be flagged for close scrutiny. By no means, shall the 100% rating be exceeded without regard in planning studies.

FERC Order 881

Summary of Order

FERC Order 881 is intended to enhance the efficiency of the transmission system while improving transparency of transmission line ratings. The Order requires transmission providers, including independent system operators (ISOs) and regional transmission organizations (RTOs), to implement ambient adjusted ratings (AARs) on the transmission lines over which they provide transmission service unless otherwise subject to an exception. Implementation of these changes are required by July 12, 2025.

Generally, a transmission line rating is representative of the maximum transfer capability of a transmission line calculated per the equipment rating methodology of each transmission owner. These transmission line ratings account for technical limitations on conductors and relevant transmission equipment (e.g., circuit breakers, disconnect switches, line traps, current transformers, voltage transformers, etc.) thermal limitations and accounts for any associated stability issues (voltage and transient stability) in the transmission system. For example, a transmission line is impacted by the current flowing in a conductor, conductor type, and resistance of the conductor. Along with the above the rating is impacted by ambient weather conditions (e.g., temperature, solar radiation, wind speed, and direction).

Static transmission line ratings are generally determined based on a pre-determined set of conservative assumptions for location and ambient weather conditions. The conservative assumptions used in a line conductor rating methodology can vary from transmission owner to transmission owner. For example, a transmission owner could utilize historical weather data sets such as the ERA5[1] dataset or TMY3[2] datasets to perform statistical analysis over a given period and then consider potential tolerances for risk to arrive at parameters needed to utilize available mathematical models in an effort to determine a static transmission line rating. Further, the same information could be leveraged to determine static continuous seasonal ratings as compared to single rating for use over an entire year.

That said, IEEE/CIGRE standards provide methods to calculate ratings for overhead transmission lines. One methodology could leverage IEEE 738 steady state heat balance equations to calculate normal continuous ratings. Both ambient adjusted temperature changes and solar heating changes could be accounted for in these equations as well.

FERC Oder 881 establishes the following parameters for AARs:

- Applies to a time period not greater than one hour
- Reflects up-to-date forecast of ambient air temperature across the time period
- Status of solar heating, e.g. accounts for daytime/nighttime solar heating changes
- Calculated at least once for each hour for 240 hours (i.e. 10 days) into the future
- Updates to sunrise/sunset times time used to calculate ratings at least monthly

[1] ERA5 is provided by the European Centre for Medium-Range Weather Forecasts (ECMWF)
[2] TMY3 is provided by the National Renewable Energy Laboratory (NREL)

- Address how AARs for transmission lines interact with system stability limits, remedial action schemes, and system operating limits

The Order requires that AARs must reflect the temperature at which there is sufficient confidence that the actual temperature will not be greater than that temperature (expected temperature and an appropriate forecast margin). The Order also requires that the ratings be calculated for at least a historical range of temperature +/- a margin of 10 degrees Fahrenheit.

If transmission owners choose to develop rating look up tables for their equipment, the table should have a rating available for every 5-degree Fahrenheit change of temperature.

Seasonal ratings are required to be utilized in the longer-term reliability studies/availability transfer capability (ATC) studies. The Order requires development of seasonal ratings over a minimum four (4) seasons. Transmission owners are responsible for defining season start and end times in their transmission line rating methodologies.

There are ongoing efforts to coordinate implementation of AARs. This ranges from coordination on seasonal definitions, how to provide the information to neighboring Transmission Operators, Balancing Authorities, and Reliability Coordinators. This is a significant undertaking as it expands beyond the requirements of North American Electric Reliability Corporation (NERC) reliability standard FAC-008 and requires additional coordination among multiple parties in a real-time fashion in determining the most limiting rating on a transmission line by transmission line basis.

Lastly, FERC Order 881 does not explicitly require the implementation of dynamic line ratings (DLRs) but does currently leave the door open to their use.

Potential Issues

While numerous parties have pointed to the possibilities of benefits that may be realized by the implementation of Order 881, it appears that fewer have yet to realize or understand that there is potential for negative impacts.

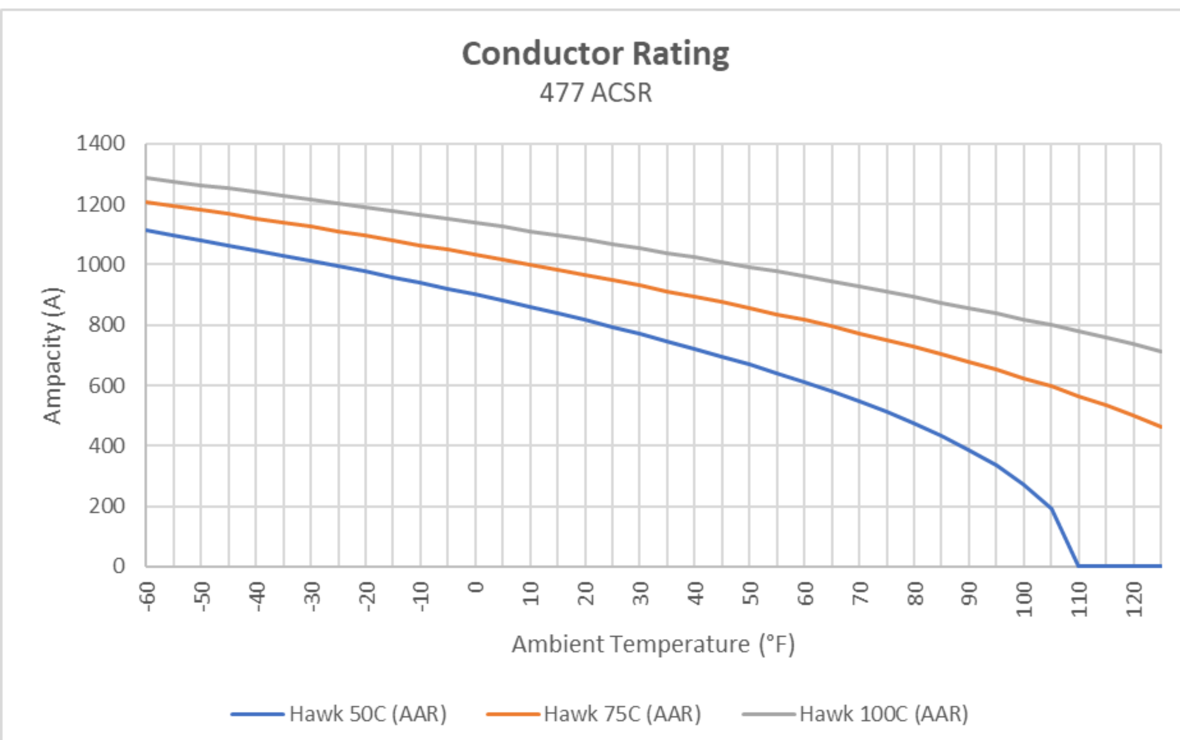
Starting with the positives, many have indicated that AAR could produce cost savings as this could free up latent transmission line capacity that is unrealized with existing transmission line ratings methodologies. This seems to point to the fact that it would potentially allow for less curtailment of wind or solar generation and thereby decreased costs.

Looking at the negatives, it should be noted that FERC Order 881 specifically requires the implementation of AARs. There are only two (2) factors at play once wind speed and direction along with solar heating are determined and fixed based on available data. These are ambient temperature and sunrise/sunset. It should be noted that if lookup tables are developed there are two different sets (when the sun is shining, and when it is dark outside) which are coupled with ambient temperature. If ambient temperature is adjusted from -60 F to 125 degrees F we can see that as we experience higher ambient temperatures the capability of transmission lines are reduced. This is largely because the heat balance equation from IEEE 738 (shown below) cannot be solved for any real value of I as at higher temperatures the conductor is exceeding the Maximum Operating Temperature (MOT) with zero current flow.

$$I = \sqrt{\frac{Q_c + Q_r - Q_s}{R(T)}}$$

- I = Rated Current
- R(T) = The resistance of the conductor at MOT
- Q_s =Heating due to solar radiation
- Q_c = Cooling due to convection
- Q_r = Cooling due to heat radiating from the conductor

The plot below, which is not reflective of any transmission owner methodology, is an example of how the conductor MOT, along with changes in ambient temperature, can impact line ratings assuming all other parameters are fixed. The MOT is the maximum operating temperature to which a transmission line is designed considering factors such as sag clearances among others. These are represented by the "50C", "75C," and "100C" labels associated with each curve and correspond to a design standard considering 50°C, 75°C and 100°C as the MOT. This diagram is intended to be representative of how over a given ambient temperature range a conductor's "capacity" changes with disregard for any exceptions or stability limitations, etc. Dependent on the existing methodology of a transmission owner, this could range from minor to significant losses in capacity at higher ambient temperatures. While reduction in "capacity" may occur during times of low wind/solar generation production, it could also potentially lead to undesired impacts to load serving capabilities during the same period.



The diagram above is reflective of the following assumed environmental assumptions.

Wind Speed	4 ft/s
Wind Angle	90°
Line Orientation	North-South

Reference Date (for Solar Position)	June 21st
Atmosphere	Clear
Time of Day	12:00 (day)
Absorptivity	0.5
Emissivity	0.5
Latitude	39.5
Altitude	5000 ft

There are tradeoffs between Static and AAR ratings. While most see the advantages during "cooler" periods, it should be noted that this may lead to the need for additional transmission investment to resolve load serving issues and an inability to transfer surplus energy from Colorado externally or bring energy into the state from outside of the state during periods of energy deficiencies.

Annual Generation Capacity Table

Per Decision No. R22-0690 ¶ 30, utilities are to provide a table presenting the annual expected capacity for each existing and planned resource within their generating portfolio inclusive of power purchase agreements.[1] The table provided here is outlines Tri-State's generation portfolio. Each study that is evaluated considering a specific year and each model that is developed within WECC take into account the changes to Tri-State's generation portfolio. For example, studies performed in the year 2023 considered that Tri-State's allocation at Craig is 0 MW for study years 2030 and beyond.

[1] Contracts outside of power purchase agreements (PPAs) are not included. Megawatt (MW) values shown are reflective of "unit net capacity" as reported in Tri-State's 2023 ERP Phase I, which is rated capacity available to serve load and sales; except for units not wholly owned by Tri-State, where only Tri-State's portion of net capacity is shown. Not reflective of seasonal capacity, electric load carrying capability (ELCC), or forced outage rate adjustments.

			Year										
Units	**Point of Interconnection**	**Gen Type**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Craig U1	Craig 230 kV	Coal	102	102	0	0	0	0	0	0	0	0	0
Craig U2	Craig 230 kV	Coal	98	98	98	98	98[2]	0	0	0	0	0	0
Craig U3	Craig 345 kV	Coal	448	448	448	448[3]	0	0	0	0	0	0	0
J.M. Shafer Unit 1	J.M. Shafer	Gas	40	40	40	40	40	40	40	40	40	40	40
J.M. Shaffer Unit 2	J.M. Shafer	Gas	40	40	40	40	40	40	40	40	40	40	40
J.M. Shaffer Unit 3	J.M. Shafer	Gas	40	40	40	40	40	40	40	40	40	40	40
J.M. Shaffer Unit ST	J.M. Shafer	Gas/Steam	36	36	36	36	36	36	36	36	36	36	36
J.M. Shaffer Unit ST2	J.M. Shafer	Gas/Steam	36	36	36	36	36	36	36	36	36	36	36
J.M. Shaffer Unit 4	J.M. Shafer	Gas	40	40	40	40	40	40	40	40	40	40	40
J.M. Shaffer Unit 5	J.M. Shafer	Gas	40	40	40	40	40	40	40	40	40	40	40
Burlington Unit 1	Burlington	Oil	60	60	60	60	60	60	60	60	60	60	60
Burlington Unit 2	Burlington	Oil	60	60	60	60	60	60	60	60	60	60	60
Limon Unit 1	Lincoln Switch	Gas	77	77	77	77	77	77	77	77	77	77	77
Limon Unit 2	Lincoln Switch	Gas	77	77	77	77	77	77	77	77	77	77	77
Knutson Unit 1	Brighton Switch	Gas	77	77	77	77	77	77	77	77	77	77	77
Knutson Unit 2	Brighton Switch	Gas	77	77	77	77	77	77	77	77	77	77	77
Kit Carson	Landsman Creek	Wind	51	51	51	51	51	51	51	0	0	0	0
Colorado Highlands Wind	Wildhorse Creek	Wind	94	94	94	94	94	94	94	94	94	0	0
Carousel Wind	Burlington	Wind	150	150	150	150	150	150	150	150	150	150	150
San Isabel Solar	Ludlow - Pinon Canyon 115 kV	Solar	30	30	30	30	30	30	30	30	30	30	30
Twin Buttes II	Lamar (PSCO) 230 kV	Wind	75	75	75	75	75	75	75	75	75	75	75
Crossing Trails	Windtalker	Wind	104	104	104	104	104	104	104	104	104	104	104
Spanish Peak Solar	Walsenburg - Gladstone 230 kV	Solar	0	100	100	100	100	100	100	100	100	100	100
Axial Basin Solar	Craig - Meeker 345 kV	Solar	0	145	145	145	145	145	145	145	145	145	145
Dolores Canyon Solar	Cahone 115 kV	Solar	0	110	110	110	110	110	110	110	110	110	110
Niyol Wind	North Yuma 230 kV	Wind	200	200	200	200	200	200	200	200	200	200	200
Spanish Peak II Solar	Walsenburg - Gladstone 230 kV	Solar	0	40	40	40	40	40	40	40	40	40	40
Laramie River Station Unit 1	Laramie River Station 345 kV	Coal	241	241	241	241	241	241	241	241	241	241	241
Laramie River Station Unit 2	Laramie River Station 345kV	Coal	243	243	243	243	243	243	243	243	243	243	243
Springerville Unit 3	Springerville 345 kV	Coal	417	417	417	417	417	417	417	417[4]	0	0	0
Pyramid Unit 1-4	Pyramid	Gas	186	186	186	186	186	186	186	186	186	186	186
Cimarron First Solar	Bison 115 kV	Solar	30	30	30	30	30	30	30	30	30	30	30

[2] Craig Unit 2 is considered as available through September 2028.

Alta Luna Solar	Caballo – Mimbres 115 kV	Solar	25	25	25	25	25	25	25	25	25	25	25
Escalante Solar	Escalante 230 kV	Solar	0[5]	200	200	200	200	200	200	200	200	200	200
4hr Battery (Planned-Generic)	New Mexico	Storage	0	0	50	50	50	50	50	50	50	50	50
Solar (Planned-Generic)	West Colorado	Solar	0	0	140	140	140	140	140	140	140	140	140
Wind (Planned-Generic)	Wyoming/ W. Nebraska	Wind	0	0	0	0	200	200	200	200	200	200	200
Gas with CCS (Planned-Generic)	West Colorado	Gas	0	0	0	0	290	290	290	290	290	290	290
Solar (Planned-Generic)	New Mexico	Solar	0	0	0	0	0	100	100	100	100	100	100
4hr Battery (Planned-Generic)	East Colorado	Storage	0	0	0	0	0	50	50	50	50	50	50
Wind (Planned-Generic)	East Colorado	Wind	0	0	0	0	0	100	100	100	100	100	100
Wind (Planned-Generic)	East Colorado	Wind	0	0	0	0	0	0	100	100	100	100	100
Wind (Planned-Generic)	Wyoming/ W. Nebraska	Wind	0	0	0	0	0	0	100	100	100	100	100
100hr Iron Air (Planned-Generic)	East Colorado	Storage	0	0	0	0	0	0	100	100	100	100	100
Wind Hybrid (Planned-Generic)	New Mexico	Wind/Storage	0	0	0	0	0	0	0	200	200	200	200

[3] Tri-State's most recent ERP filed in December 2023 identified a Craig 3 retirement date of January 1, 2028. Prior to 2024 studies assumed that this unit was available as shown in the table.

[4] Tri-State's most recent ERP filed in December 2023 identified a Springerville Unit 3 retirement date of September 15, 2031. Prior to the 2024 studies assumed that this unit was available as shown in the table.

[5] Escalante was included in studies as available starting December 2024. Transmission Planning assumed the unit was available in December of 2024, but due to the limited amount of time over the given year it would be available, it is indicated in the table as 0 MW for the year.