Appendix P

Public Service Company

Supporting Documents

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PSCo Reliability Criteria

This section sites the PSCo System Performance Criteria for steady-state, transient stability and voltage stability simulations for planning events established in Table 1 of the NERC Standard TPL-001-4 and WECC Regional Criterion TPL-001-WECC-CRT-3.

Thermal Violation (Overload) Criteria

Thermal violations requiring corrective actions are identified in steady-state simulations for:

- System Intact (P0), single contingency (P1, P2-1) and two overlapping single contingency (P6) planning events by using the seasonal normal (continuous) facility rating of overhead/underground transmission lines as well as transformers;
- Multiple contingency (P2 to P5 and P7) planning events by using the seasonal normal (continuous) facility rating of overhead transmission lines and the short-duration (or emergency) facility rating of transformers and underground transmission lines.

Elements with thermal loading >100% of applicable seasonal facility rating are identified as facilities requiring overload mitigation.

Steady State Voltage Limit Violation Criteria

These criteria are the same as that specified in WR1, parts 1.1.1 and 1.1.2 in the WECC Regional Criterion TPL-001-WECC-CRT-3.

Voltage violations requiring corrective actions are identified in steady-state simulations when steady-state voltages at PSCo (EHV and HV) BES buses are outside the following acceptable voltage limits:

- Normal (no contingency) conditions: Vmin = 0.95 pu, Vmax = 1.05 pu
- Post-contingency conditions: Vmin = 0.90 pu, Vmax = 1.10 pu

The screening criterion for generator voltage ride through capability is 0.90 pu to 1.10 pu for all planning event (P1 to P7) contingencies (R3.3.1.1). If the initial screening simulation indicates that the generator bus voltage is outside this range, follow up simulations are performed as necessary based on a review of the generator's actual voltage ride through capability.

Post-Transient Voltage Deviation Criteria

Post-Contingency steady-state voltage deviation at each applicable BES bus serving load shall not exceed 8% for P1 events. These are the same as specified in WR1, part 1.2 in the WECC Regional Criterion TPL-001-WECC-CRT-3.

Transient Voltage Response (Dip) Criteria

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.

These are the same as specified in WR1, parts 1.3, 1.4 and 1.5 in the WECC Regional Criterion TPL-001-WECC-CRT-3.

Voltage Stability Criteria

These are the same as specified in WR5 of WECC Regional Criterion TPL-001-WECC-CRT-3.

CCPG, and thereby PSCo, has translated WR5 to the following acceptable real power (MW) margins to the voltage instability threshold (such as the nose of P-V curve).

- Category P0-P1 Events = 5%,
- Category P2-P7 Events = 2.5%, and
- Extreme Events = 0%

Transient Stability Criteria

This comprises of two transient (dynamic) response criteria – acceptable angular stability of generating units (per R4.1.1 and R4.1.2) and acceptable damping of power oscillations (per R4.1.3). CCPG, and thereby PSCo, has adopted the following.

> Category P1 Event: No generating unit exhibits angular instability (i.e., loss of synchronism) and the relative rotor angle (power) oscillations are characterized by positive damping (i.e., amplitude reduction of successive peaks) >5% within 30 seconds.
>
> Category P2–P7 Events: Angular instability of one or more generating units may occur, provided any resulting power swing only trips the unstable generating unit(s) and does not trip any transmission facilities, thus preserving the BES stability. In addition, the relative rotor angle (power) oscillations are characterized by positive damping (i.e., amplitude reduction of successive peaks) >5% within 30 seconds.

Note that the positive damping criterion is the same as that specified in WR1, part 1.6 in the WECC Regional Criterion TPL-001-WECC-CRT-3.

Cascading and/or Uncontrolled Separation/Islanding Identification Criteria

CCPG, and thereby PSCo, has adopted the following.

A potential triggering event for Cascading will be investigated upon one of the following results:

> a) A generator pulls out of synchronism in transient stability simulations. Loss of synchronism occurs when a rotor angle swing is greater than 180 degrees. Rotor angle

swings greater than 180 degrees may also be the result of a generator becoming disconnected from the BES; or

b) A transmission element experiences thermal overload that exceeds its transmission relay loadability limit; or

c) Negative voltage stability margin.

PSCo Facility Rating Methodology

Xcel Energy

Transmission

Facility Rating Methodology

Version 14.0

November 15, 2020

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1.0 Objective

The objective of this document is to describe the methodologies employed when determining the ratings of transmission facilities on the Xcel Energy Bulk Electric Transmission Systems. The rating methodology includes both Normal and Emergency Ratings. For tables of equipment ratings and example calculations please refer to the Xcel Energy Rating Methodology Supplement. The Supplement is not considered part of the Rating Methodology, because all information pertaining to the method of the calculation is included in the Rating Methodology. The Supplements are in two parts; there are Excel Spreadsheets, which contain tables of calculated ratings, along with word documents explaining the development of the Rating Methodology and example calculations. Xcel Energy is currently developing software to calculate all bulk electric system facility ratings as the primary system. Once the published facility ratings are created with the software, the Supplement tables and example calculations will be secondary.

The Xcel Energy Bulk Electric Transmission Systems includes the combined Northern States Power Company Minnesota and Northern States Power Company Wisconsin (NSPM and NSPW) Transmission System, Public Service Company of Colorado (PSCo) Transmission System, and the Southwestern Public Service (SPS) Transmission Systems.

2.0 General Information

2.1. Updates

Once a revised Facility Rating Methodology has been approved, Xcel Energy will review and update rating information and issue new ratings (if needed) within 24 months.

2.2. Facility Ratings

The Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility. Ratings of the equipment that comprise the Facility shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
- One or more industry standards developed through an open process such as Institute of Electrical and Electronics Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis. The equipment shall include, but not be limited to, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices. The rating for each individual piece of equipment considers the (a) Equipment Rating standard(s) used in development of this methodology; (b) Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications; (c) Ambient conditions (for particular or average conditions or as they vary in real-time); and (d) Operating limitations; in accordance with good utility practice. Operational limitations may result in a de-rating based on good utility practice. The Facility Rating will include both Normal and Emergency Ratings.

Xcel Energy develops a 30-minute emergency facility rating for all Transmission Lines. The emergency rating timeframes available for transformers are published in the Criteria for Power Transformer Loading. IEEE equipment standards have varying time frames for equipment emergency ratings. If the emergency rating developed for a piece of equipment is for a longer duration than that of the reported rating, then the equipment's emergency rating is utilized in determining the Facility's Emergency Rating. For example, it is acceptable to use a switch's four-hour emergency rating when determining the 30-minute emergency rating of a transmission line. However, when the duration of an emergency rating of a piece of equipment is less than the duration of the rating being reported, then the equipment's normal ratings will be utilized. For example, it is not acceptable to use a switch's 4-hour emergency rating when determining the 8-hour emergency rating for a transformer facility. Instead, the switch's normal continuous rating will be used in determining the 8-hour emergency rating for the transformer facility.

2.3. Transmission Line Facility Ratings

When developing a Transmission Line Facility Rating, the set of equipment that comprises the Facility includes:

a. The transmission line.

b. All of the equipment that is used to operate or disconnect the line and operated as part of the line. This includes, but is not limited to adjacent circuit breakers, disconnect switches, conductor, relays, and meters that as a result of switching could be operated in series with the line.

The Transmission Line Facility Rating is calculated as the minimum rating of the equipment described above.

2.4. Transformer Facility Ratings

When developing a Transformer Facility Rating, the set of equipment that comprises the Facility includes:

a. The transformer equipment.

b. All of the equipment that is used to operate or disconnect the transformer and operated as part of the transformer. This includes, but is not limited to adjacent circuit breakers, disconnect switches, conductor, relays, and meters that as a result of switching could be operated in series with the transformer.

The Transformer Facility Rating is calculated as the minimum rating of the equipment described above.

2.5. SPP, WECC and MRO

Where SPP, WECC and MRO have requirements for facility ratings, the more conservative rating should be used.

2.6. Jointly-Owned Facilities

Equipment ratings on Jointly-Owned facilities will be communicated between the owners. The Jointly-Owned Facility Rating shall equal the most limiting applicable Equipment Rating of the individual piece(s) of equipment that comprise the Jointly-Owned Facility.

In cases where a facility is owned in segments (such as a line terminal being owned by one party and the line conductor by another party), Xcel Energy rates only those portions of the line/terminal/transformer that it owns and provides that information to the owner(s) of the other segment(s). Xcel Energy takes into account rating data provided by the owner(s) of the other segment(s) of the line or transformer, and applies the most limiting rating as the Facility Rating.

2.7. Conservative Ratings

A limited number of pieces of equipment may not have all the information necessary for developing an equipment rating. However, in order to provide system ratings, a conservative rating may be applied to this equipment. The conservative rating for the equipment must be documented in the equipment attributes. Conservative ratings are defined as those, which produce an ampacity on the low end of the possible range for that equipment and are based upon engineering judgment. A Rating Exception Form must be on file for all conservative ratings developed.

2.8. Default Ambient Temperature

Design Ambient Temperature	NSP	PSCo	SPS
Summer Ambient Design Temperature	40 °C 104 °F	40 °C 104 °F	40 °C 104 °F
Winter Ambient Design Temperature (used for winter peaking circuits – these circuits peak at very low temps)	0 °C 32 °F	24 °C 75 °F	27 °C 81 °F

For elevations greater than or equal to 5500 feet in the PSCo region, ambient temperatures in the following table may be used for calculating ampacity of conductors & equipment.

Elevation (feet)	Summer Ambient Design Temperature	Winter Ambient Design Temperature
5500-6000	40°C = 104°F	24°C = 75°F
6001-6500	39°C = 101°F	24°C = 75°F
6501-7000	37°C = 99°F	24°C = 75°F
7001-7500	36°C = 97°F	24°C = 75°F
7501-8000	35°C = 95°F	23°C = 73°F
8001-8500	34°C = 93°F	22°C = 71°F
8501-9000	33°C = 91°F	21°C = 69°F
9001-9500	32°C = 89°F	20°C = 67°F
9501-10000	30°C = 87°F	19°C = 66°F
>10001	29°C = 85°F	18°C = 64°F

The Winter Operating Seasons are:

- December 1 – March 1 for NSPM and NSPW
- November 1 – March 31 for PSCo
- December 1 – March 31 for SPS

Ambient temperature assumptions are used for standards that do not state assumptions.

2.9. Ambient-Adjusted Ratings

Ambient-Adjusted Ratings may be used for real-time operations and near-term planning; however, long-term planning should not rely on Ambient-Adjusted Ratings. Typically, these ratings will rely on weather parameters for ambient temperature but may also be based on wind speed or other ambient-based parameters. In real-time operations, these ambient parameters will be obtained from local meteorological stations or from the weather service in the vicinity of the affected facility. In the case where facilities cross areas of differing weather conditions, the more conservative values will be utilized.

Once the ambient parameters are known, the Ambient-Adjusted Rating for one or more elements of the Facility may be determined by various methods. A few of the common methods are listed but other methods may be used.

- Recalculated Ambient Adjusted Rating tables
- Standalone program utilizing comparable rating calculation
- EMS dynamic rating feature
- Line monitors

If Ambient-Adjusted Ratings are applied to some but not all elements of a Facility, then the normal seasonal ratings are to be used for those elements, which do not have an Ambient-Adjusted Rating when determining the overall Facility rating.

The Ambient-Adjusted Ratings are not to exceed the maximum published facility rating unless a detailed review of relay settings is completed.

2.10. Operational Guidelines

Operating Guidelines may be utilized in cases where recent field verification has identified a potential discrepancy in the assumptions used to determine the rating of an element and the resulting facility de-rate would result in significant risk to the operation of the transmission system. These Operating Guidelines will be temporary, with the assumption that once the resulting remediation project is complete, then the Operating Guideline will be removed and the calculated rating will be implemented.

3.0 Transmission Line Rating Methodology

Xcel Energy uses the IEEE 738-2006 standard for calculating bare overhead conductor ratings. Xcel Energy will use the lesser of the Conductor Maximum Operating Temperature and the Clearance/Hardware thermal limits for conductor operating temperature in the IEEE 738-2006 calculation. The remainder of this section lists assumptions.

3.1. Conductor Maximum Operating Temperature

Xcel Energy adheres to the following table for maximum operating temperature of its conductors. The table shows normal and emergency limits.

Conductor type	Normal (Operating Temperature)	30 Minute Emergency Rating
ACSR*	100 °C	Normal Rating X 110%
ACAR	100 °C	Normal Rating X 110%
AAC	100 °C	Normal Rating X 110%
Cu	95 °C	Normal Rating X 110%
Copper Weld	95 °C	Normal Rating X 110%
ACCC	180 °C	200 °C
ACSS	200 °C	250 °C
SCACAR	100 °C	Normal Rating X 110%
ACCR	210 °C	240 °C
ZTACSR	210 °C	240 °C

*ACSR may be permitted to run at higher temperatures see “General Guidelines when considering up-rating ACSR beyond 100 degrees C” in Rating Methodology Supplement.

3.2. Permitting/Other

Conductor may be rated below the maximum operating temperature listed in section 7.1 for the following reasons:

- Permitted ROW agreements (ex. railroad or waterway crossing).
- Ampacity (ex. NESC clearance limitation).
- EMF calculations.

3.3. Clearance/Hardware Limit

The Clearance/Hardware thermal rating of a transmission line is the maximum temperature, (regardless of the current) which a conductor can attain without violating code-mandated clearances or damaging temperature limited hardware. Short-term limitations due to clearance restrictions will be considered on a case by case basis.

3.4. Remaining Assumptions

Variables	NSP – Assumption	PSCo – Assumption	SPS – Assumption
Conductor properties	Southwire Overhead Conductor Manual 2nd Edition and other various sources	Southwire Overhead Conductor Manual 2nd Edition and other various sources	Southwire Overhead Conductor Manual 2nd Edition and other various sources
Cooling Wind	Maximum of 4 ft/sec @ 90deg to conductor *	Maximum of 4 ft/sec @ 90deg to conductor	Maximum of 6 ft/sec @ 90deg to conductor
Elevation	Actual Elevation (or use default of 1100')	Actual Elevation (or use default of 5200')	Actual Elevation (or use default of 3700')
Emissivity	0.5	0.5	0.5
Absorptivity	0.5	0.5	0.5
Latitude	Actual Latitude (or use default of 43°N)	Actual Latitude (or use default of 40°N)	Actual Latitude (or us default of 35°N)
Summer Day Solar Calc	172	172	172
Winter Day Solar Calc	90	90	90
Time of Day	12:00 PM	12:00 PM	12:00 PM
Orientation of Line	Actual Orientation (or use default of East to West)	East to West	East to West
Atmosphere	Clear	Clear	Clear

***Excludes Buffalo Ridge Wind Rated Lines**

3.5. CAPX Assumptions

CapX2020 is a joint initiative of 11 transmission-owning utilities in Minnesota and the surrounding region to construct region transmission lines. These lines are to be owned jointly as a percentage share in the line. The following assumptions have been agreed upon by the utilities for rating calculations.

Variables	CAPX2020 – Assumption
Conductor properties	Southwire Overhead Conductor Manual 2nd Edition and other various sources
Cooling Wind	2 ft/sec @ 90deg to conductor
Emissivity	0.7
Absorptivity	0.9
Summer Day Solar Calc	July 8th
Winter Day Solar Calc	April 30th
Time of Day	12:00 PM
Orientation of Line	East to West
Atmosphere	Clear

3.6. Buffalo Ridge Wind Rated Lines

A few transmission lines in southwestern Minnesota that provide outlet to wind generators have a rating based on a higher wind speed than is typical throughout the rest of the NSP system. Higher output from the wind generators is only available during the time periods where the wind speed is higher than used in normal transmission line ratings. Thus a higher wind speed was used to rate these lines. The higher wind speed was approved at the time of development by the Design Review Subcommittee of the then existing NERC Reliability Region “Mid-Continent Area Power Pool (MAPP).

The transmission line circuits in the NSP Transmission System with wind ratings are the following 115kV lines: Split Rock-Pipestone and Chanarambie-Pipestone.

3.7. Underground Lines

Underground lines have been and will be rated on an individual basis using engineering analysis. The ratings are developed and based on the soil conditions, conductor type, and installation methods.

Underground cable and the associated terminators are engineered as a system and the ampacity rating is determined for the system. The ampacity rating provided for underground cable and terminator systems shall equal the most limiting element of the system.

4.0 Transmission Line Equipment Rating Methodology

4.1. Line Switches

The line switch ratings are based on the manufacturer's assigned nameplate rating and ACCC designation. The maximum ampacity to operate the switch is based on the IEEE C37.37 loading guide.

4.2. Line Jumpers

The rating methodology for line jumpers is the same as that used as for Xcel Energy's Transmission Lines, which references IEEE STD. 738. The ratings communicated for transmission lines will represent the rating of the line including all jumpers in the line. If the rating of a jumper is the limiting equipment in a line, then the rating of the line will be limited to the jumper rating.

Jumpers between transmission lines and the substation equipment should be rated per the transmission line rating methodology unless restricted by the equipment or hardware that the jumper is attached to.

4.3. Hardware

Hardware for transmission lines is temperature limited and is designed for the operating temperature of the line. The equipment manufacturer provides hardware ratings.

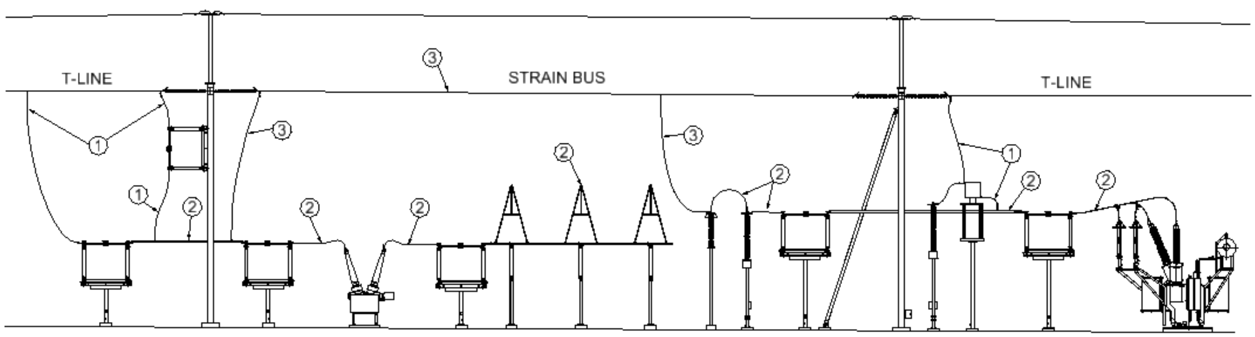
5.0 Transmission Substation Equipment Rating Methodology

Transmission Substations are comprised of several pieces of equipment. Each piece of equipment is identified below along with its ratings methodology.

The following diagrams are to be used as reference for the Substation Equipment Rating Methodology.

5.1. Substation Rating Diagrams

SUBSTATION RATING DIAGRAM



① T-LINE TO SUBSTATION EQUIPMENT - RATE ONLY FLEXIBLE CONDUCTORS PER *TRANSMISSION LINE RATING METHODOLOGY* SECTION;
DERATE CONDUCTORS WHEN CONNECTED DIRECTLY TO:

DEVICES WITH BUSHINGS	-	NORMAL 85°C	EMERGENCY 100°C,
LINE TRAPS	-	NORMAL 135°C	EMERGENCY 135°C,
SWITCHES	-	NORMAL 200°C	EMERGENCY 200°C;

ALL CONDUCTORS' RATINGS SHALL FOLLOW *CONDUCTOR MAXIMUM OPERATING TEMPERATURE* TABLE.

② SUBSTATION OR STRAIN BUS TO TUBE, BUSHING OR EQUIPMENT:

ALL CONDUCTORS	-	NORMAL 85°C	EMERGENCY 100°C

③ REFER TO THE CRITERIA UNDER *BUS CONDUCTORS AND EQUIPMENT JUMPERS* SECTION TO DETERMINE WHETHER SUBSTATION OR TRANSMISSION RATING METHODOLOGY IS APPLICABLE.

5.2. Bus Conductors and Equipment Jumpers

The rating methodology is as outlined in IEEE Standard 605 for tubular bus and IEEE Standard 738 for wire bus and jumpers. Assumptions made for conductors are as follows:

Variables used for Bus Conductor (Tube, Wire & Jumpers) Ampacity Calculations			
Variables	**NSP**	**PSCO**	**SPS**
Summer Ambient Temperature (Deg. C)	See Default Ambient Temperature under General section		
Winter Ambient Temperature (Deg. C)			
Emissivity Outdoors(e)	0.5	0.5	0.5
Emissivity Indoors(e)	0.35	N/A	N/A
Absorptivity (a)	0.5	0.5	0.5
Degrees North Latitude	Actual (or 43)	Actual (or 40)	Actual (or 35)
Time	12	12	12
Atmosphere	Clear	Clear	Clear
Elevation (ft.)	Actual (or 1100)	Actual (or 5900)	Actual (or 3700)
Wind Speed (ft./S) – indoor	0	0	0
Wind Speed (ft./sec.) - enclosed substation	2	2	2
Wind Speed (ft./sec.) - open substation	4	4	6
Wind Direction Factor (deg.)	90	90	90
Azimuth of Conductor (deg.)	90	90	90
Day of the year - Summer (Variable N from IEEE 738)*	172	172	172
Day of the year - Winter (Variable N from IEEE 738)*	90	90	90

*No solar heat gain for indoor conductors

All tube and bare overhead conductors inside the substation will have a normal rating of 85^{o} C and an emergency four hour rating of 100^{o} C. Jumpers between transmission lines and the substation equipment should be rated per the transmission line rating methodology unless restricted by the equipment or hardware that the jumper is attached to. Strain bus consisting of bare overhead conductor may be rated per the Transmission Line Rating Methodology if all of the following are true:

1. The strain bus is considered an extension of the transmission line due to the fact that one end of the strain bus terminates on the transmission line dead-end structure.
2. The strain bus terminations inside the substation are at the same height as or higher than the transmission line termination into the substation or minimum conductor ground clearance greater than 25 feet above surface grade.
3. The strain bus is in an open substation and is expected to be exposed to the same wind speed as the transmission line.

4. Structures and hardware used to install the strain bus are rated for the maximum conductor temperature and tension as outlined by the Transmission Line Rating Methodology.
5. Clearances to ground and other substation equipment can be maintained at maximum sag based on company standards when designed.

Connectors and terminations used on substation conductors will be given a rating equal to that of the conductor to which they are attached. Therefore, the ratings communicated for substation conductors will include the rating of the conductor itself as well as the connectors and terminations connected to it.

5.3. Proximity Effect of Conductors

Conductors spaced less than six inches apart are subject to reductions of capacity due to proximity effect. Xcel Energy has used Engineering Analysis to develop proper ratings for these conductors. Xcel Energy has developed ratings on these conductors based on three sources. "Skin Effect and Proximity Effect in Tubular Conductors", "Skin Effect in Tubular and Flat Conductors," and "Bessel Functions for A-C Problems" were used in formulating the calculation.

5.4. Circuit Breakers, Circuit Switchers, and Line-Switchers

The rating methodology is as outlined in ANSI/IEEE C37.010. Breakers pre 1964 utilize a 55 degree C Hot Spot temperature rise and 1964 – present utilize a 65 degree C Hot Spot temperature rise.

5.5. Disconnect Switches

The rating methodology is as outlined in ANSI/IEEE C37.30 and ANSI/IEEE C37.37. Xcel Energy has contacted switch manufacturers about connecting conductors, which will operate at 200°C to switch pads. The manufacturers have provided test data and have stated that this will not adversely affect the operation of the switches.

5.6. Transformers

The rating methodology is as outlined in ANSI/IEEE C57.12.00. Loading/rating for loading above transformer nameplate is in accordance with ANSI/IEEE C57.91. The ratings for transformers are determined by the Criteria for Power Transformer Loading.

5.7. Current Transformers (CT's)

The overload capacity of a Current Transformer (CT) is determined by its continuous thermal rating factor (RF). The continuous thermal rating factor is defined in IEEE C37.110. The maximum secondary current of a CT is the rated value of the CT secondary*RF or as limited by other elements in the circuit.

$Itap = Itap_r * RF$

Itap = adjusted rated continuous current of specific CT tap under consideration

$Itap_r$ = rated continuous current of tap

RF = Continuous thermal rating factor (Manufacturer should be consulted for value of continuous current rating factor. Assume 1 if not available.)

5.7.1. Autotransformer neutral winding CTs

CTs on the neutral winding of an autotransformer do not experience the same current flows as the H or X windings. The method of calculating the flow in the common winding uses the following formula:

$$CommonWindingAmps = \frac{TopRating(KVA)}{\sqrt{3} * V_{lowside}(kV)} - \frac{TopRating(KVA)}{\sqrt{3} * V_{highside}(kV)}$$

This formula is applied to find the amperage flowing through the common winding when the transformer is operating at its top rating.

5.8. Power Apparatus Bushings

This section applies to power apparatus bushings as defined by IEEE C57.19.00 that have basic impulse insulation levels of 110 kV and above for use as components of oil-filled transformers and oil-filled reactors. Bushings supplied with other equipment will be rated using the same methods as the equipment they are attached to.

Bushings can be loaded up to their specified ampere rating. The overload rating of the equipment on which the bushing is installed could be limited by the bushing ampere rating. If the bushing rating cannot be confirmed by name plate or contacting manufacturer, the equipment will be rated at its nameplate rating or calculated rating with no overload. However, if the equipment was specified to have an overload rating, or if the equipment manufacture has documented an overload rating, this overload rating may be used.

5.9. Line Traps

The terms Line Traps and Wave Traps are used interchangeably throughout this document.

The ratings methodology for the wave trap is according to IEEE Std C93.3-2017 The wave trap allows for loadability to change due to ambient temperature and emergency operating conditions. The maximum terminal temperature for a wave trap is 135 degrees C. Altitude derating factors in C93.3-2017 include an elevation adjustment with a lower mean (24 hour) maximum temperature. Line traps should therefore not be ambient adjusted per the elevation table in section 6.8 above.

5.10. Shunt Reactors

The ratings methodology for shunt reactors (oil filled) is according to ANSI/IEEE C57.21. There is no emergency or overload rating for shunt reactors. Shunt reactors may be operated up to 105% of the rated voltage.

5.11. Shunt Capacitors

IEEE standard 18 specifies the technical requirement of individual capacitor units and IEEE 1036 provides the application guidelines for shunt capacitor banks.

5.12. Series Capacitors

All series Capacitors will be rated per manufacture specifications for normal and emergency conditions.

5.13. SVC (Static Var Compensators)

SVC's will be rated per the manufacturers recommended ratings for normal and emergency conditions.

5.14. DC Tie Equipment

DC Tie equipment will be rated per the manufacturers recommended ratings for normal and emergency conditions.

5.15. GIS Equipment

All Gas Insulated Substation (GIS) equipment will be rated per manufacture specifications for normal and emergency conditions.

5.16. Protective Relay & CT Secondary Devices

All secondary devices will be operated within their specified manufacturer limits. If the rating for a secondary device cannot be determined then assume the rating is 5 amps.

Protective relay settings on all equipment in the bulk electric transmission system should be designed and set to permit the emergency loading of equipment per NERC standard PRC-023 where applicable. PRC-023 shall be followed with respect to any settings that may affect facility ratings.

The over-current relays on the transmission lines used for “switch-onto-fault” should be designed and set above the maximum loading of the line.

Over-current relays on transformers should be designed and set above the maximum emergency loading.

PSCo Load Forecast Information

Public Service's 2021 ERP forecast native peak demand (retail and firm wholesale requirements) is expected to grow at a compounded annual rate of 0.3 percent through 2030. This compares to average annual growth over the past five years of 1.9 percent. The retail segment drives the peak growth, averaging 1.3 percent annual growth. Native peak demand is expected to be slower than the past five years due to declines in wholesale peak demand. The declines in wholesale peak are primarily driven by contracts expiring.

The forecast assumes an increase in adoption of electric vehicles ("EVs") through the forecast period. By 2030, the company expects about 450,000 EVs in its service territory, verses approximately 30,000 in 2020. The ERP forecast includes a lower peak demand impact due to utilizing a managed charging shape beyond 2022. EVs constitute 144 megawatts ("MW") of the base peak forecast in 2030. The EV MWs included in the forecast are included in line 11 below.

The forecasts are adjusted for the company's Demand Side Management programs ("DSM"), which is approximately 30 to 60 MW per year until 2025 and the expected savings from the Integrated Volt/Var Optimization capabilities of advanced meters. The MW adjustments to the forecast are included in lines 10 and 12 below

The ERP filing reflects native load and therefore excludes the impact of Distributed Energy Resources ("DER"). However, the DER are included in lines 14 and 18 in the chart below.

Xcel | PSCo - Demand Forecast Comparison

March 2021 ERP

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	
8	Res Base Forecast	3,191	3,207	3,213	3,229	3,238	3,267	3,297	3,325	3,335	3,364	+
9	Non-Res Base Forecast	3,261	3,410	3,428	3,436	3,449	3,464	3,473	3,480	3,488	3,496	+
10	DSM Forecast	32	41	50	59	51	25	(1)	(24)	(46)	(69)	-
11	EV's Forecast	10	11	21	34	46	59	73	91	115	144	+
12	IVVO Forecast	16	24	33	41	40	39	39	38	38	37	-
13	Oil&Gas Forecast	-	-	-	-	-	-	-	-	-	-	+
14	Solar Forecast	177	200	225	245	259	275	291	311	339	373	-
15	**Retail Forecast**	**6,237**	**6,362**	**6,354**	**6,354**	**6,383**	**6,451**	**6,515**	**6,570**	**6,608**	**6,662**	*15 = 8+ 9 - 10 + 11 - 12 + 13 - 14*
16	Wholesale Forecast	443	411	372	379	388	180	181	182	183	184	
17	**Obligation Forecast**	**6,679**	**6,773**	**6,726**	**6,733**	**6,772**	**6,631**	**6,696**	**6,752**	**6,791**	**6,846**	*17 = 15 + 16*
18	Solar Forecast	177	200	225	245	259	275	291	311	339	373	
19	**PSCo Native Load Forecast - ERP March 2021 (MW)**	**6,856**	**6,973**	**6,951**	**6,978**	**7,031**	**6,906**	**6,986**	**7,063**	**7,130**	**7,219**	*19 = 17 + 18*

Methodology Document		
Xcel Energy	Public Service Company of Colorado	
M-004 Available Transfer Capability Implementation Document (ATCID)		Version: 8.0
File Name: PSC-PRO-PSCo M-004 Available Transfer Capability Implementation Document (ATCID)		Page 1 of 20

1.0 PURPOSE

- This document serves to ensure that calculations are performed by the PSCo Transmission Service Provider to maintain awareness of available transmission system capability and future flows on the PSCo system as well as those of PSCo neighbors. Steps in this procedure are used to meet the requirements of the MOD-001-1a NERC Reliability Standard (and subsequent versions).

- Available Transfer Capability (ATC) is defined in the NERC Glossary as:

  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.

2.0 APPLICABILITY AND RESPONSIBILITIES

- Manager, Transmission Control Center – responsible for acting as the point of contact and managing the ATC processes; represents the PSCo Transmission Operator (TOP) and Transmission Service Provider (TSP) functions.

- Manager, Real Time Planning Engineering – responsible for assisting in the determination and calculation of ATC.

- Manager, Transmission Planning– responsible for representing the PSCO Transmission Planner (TP) and Planning Coordinator (PC) functions.

3.0 APPROVERS

Name	Title
Robert Staton	PSCo Control Center Manager
Dean Schiro	Manager, Real Time Planning
Michael Rein	Manager, Transmission Planning (PSCo)

4.0 VERSION HISTORY

Date	Version Number	Change
Effective 4/1/2011	1.0	Initial version – created as part of MOD-001-1 implementation
03/31/2013	2.0	Moved to Methodology folder from Procedures
04/01/2013	2.1	Errata. Added IREA to attachment 5
10/31/2014	3.0	Updated approver list and titles. Updated contact information in attachment 5.

03/31/2016	4.0	Updated contact information in Attachment 5
11/1/2017	5.0	Revised 4.1.1 to specify that Tri-State-Generation and Transmission is one of the WECC members that submits data to WECC's data bank cases. Updated Attachment 5, Notification contact information. Revised 5.3.2 to add time frame for notification of affected entities prior to effective date of change(s). Added Section 5.3.3 to ensure compliance with MOD-001-1, R5.
02/24/2020	6.0	Revised for Transition to SPP RC. Updated Mike Rein as Manager, Transmission Planning. Updated Attachment 5 contact information. Added third bullet for authorization of NERC Waiver Letter use in Section 2.1.3.3.
4/27/2020	7.0	Revised 2.1.3.11 to add Power Transfer Distribution Factor Methodology and use of Pseudo TTC; Revised 5.3.1 to distribute ATCID prior to effective date; Revised 5.3.2 to reflect change to 5.3.1
5/3/2021	8.0	Revised Counterflow section 4.1.4 to include schedules (eTags) in the non-firm ATC calcluation in the Scheduling and Operating horizons.

Methodology

1. ATC Methodology
   1.1. PSCo has selected the "Rated System Path Methodology" as described in NERC Reliability Standard MOD-029-1a to calculate ATC.

2. Calculation of Total Transfer Capability (TTC)
   2.1. The Manager, Transmission Control Center shall ensure that personnel conduct calculations using computer models to compute TTC in the following manner:
      2.1.1. Coordinate with the Real Time Planning (RTP) group and Transmission Planning (TP) group to develop and run studies that satisfy the requirements listed in Attachment 1 and the following steps.
      2.1.2. When calculating TTC, assumptions shall be no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period.
         2.1.2.1. Ensure assumptions (if used) such as contingencies, loop flow, generation re-dispatch, switching operating guides or data sources for load

forecast and facility outages are clearly identified and able to be retrieved for verification at a later date.

2.1.3. Coordinate with the RTP group to calculate TTC as follows:

2.1.3.1. Establish the TTC at the lesser of the value calculated below in steps 2.1.3.2 through 2.1.3.11 or any System Operating Limit (SOL) for that ATC Path.

2.1.3.2. Except where otherwise specified within this procedure, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:

- When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.
- When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.
- Uncontrolled separation shall not occur.

2.1.3.3. IF the power flow model determines there is a “flow limited” TTC below the facility rating, THEN the thermal rating (or historical practice methodology) of that path may be used to set TTC.

- Note – evidence must be retained to demonstrate that the path was flow limited.
- Note – this is permitted as indicated in the NERC Letter shown in Attachment 6, until superseded by subsequent approved guidance from NERC.
  - o IF the NERC waiver letter is exercised and the facility rating option is used, THEN additional review and approval shall be obtained from the Manager, Real Time Planning, and Manager, Transmission Planning for all instances. Evidence of this review and approval shall be retained (e.g. email)

2.1.3.4. IF it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), THEN set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction.

2.1.3.5. IF the TTC in the prevailing flow direction is dependant on a Special Protection System (SPS), THEN set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a SPS.

2.1.3.6. IF an ATC Path whose capacity is limited by contract, THEN set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by step 2.1.3.1.

2.1.3.7. IF an ATC Path who's TTC varies due to simultaneous interaction with one or more other paths, THEN develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

2.1.3.8. Determine if the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in step 2.1.3.1.

2.1.3.8.1. Include the resolution of this adverse impact in its study report for the ATC Path.

2.1.3.9. IF multiple ownership of Transmission rights exists on an ATC Path, THEN allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.

2.1.3.10. For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.

2.1.3.11. When necessary on ATC Paths that are Contingency Limited, utilize the Power Transfer Distribution Factor (PTDF) Methodology to adjust TTC to reflect the impacts from parallel flows, losses, and load consumption, as indicated in the steps below.

(Note - The Existing Transmission Commitments (ETC) along the ATC Path are calculated based on an assumption that 100% of those commitments will flow on the ATC Path elements. Without adjusting the TTC by using a PTDF when studies indicate the need to do so, an inherent misalignment would be present in the ATC calculation.)

2.1.3.11.1. For the Contingency Limited ATC Paths that are not determined by joint TTC studies, the following PTDF Methodology will be used to determine the posted TTC:

The Power Transfer Distribution Factor (PTDF) represents the change in flow on a line due to a change in transfer between two regions. The equation below shows the change in the MW flow (f) on line l over the change in generator output (P) at bus i.

$$PTDF_{li} = \frac{f_{l\_post} - f_{l\_pre}}{P_{i\_post} - P_{i\_pre}} = \frac{\Delta f_l}{\Delta P_i}$$

2.1.3.11.2. The PTDF of an ATC Path will be studied by calculating the change in MW flow on the defining elements between the POR and POD regions by scaling generation at the POR, and load at the POD. If there is no generation at the POR, then OASIS generation scheduled at the POR can be used. If there is not enough load at the POD, a demonstrative load may be added.

2.1.3.11.3. The MW transfer flow will be calculated using the appropriate Contingency Limited power flow case.

2.1.3.11.4. The Pseudo TTC is a calculation of the PTDF and the TTC determined in the Contingency Limited power flow case.

$$Pseudo\ TTC = \frac{TTC}{PTDF}$$

2.1.3.11.5. If the Pseudo TTC is greater than the net FAC-008 rating, the net FAC-008 rating will be the posted TTC. The MOD-029 Study Report will differentiate these paths from the Flow Limited ATC Paths. Otherwise the Psuedo TTC will be the posted TTC.

2.1.4. Create a study report that describes the steps above that were undertaken, including the contingencies and assumptions used, when determining the TTC and the results of the study. IF three-phase fault damping is used to determine stability limits, THEN the report shall also identify the percent used and include justification for use unless specified otherwise in this procedure.

2.1.5. Within 7 calendar days of the finalization of the study report, the Manager, Transmission Control Center shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path.

- Note – for PSCo, the Manager, Transmission Control Center is the PSCo TOP and TSP.

3. Calculation of Existing Transmission Commitments (ETC)

 3.1. The Manager, Transmission Control Center shall ensure that personnel conduct calculations to compute ETC use the equations in Attachment 2.

4. Calculation of ATC

 4.1. The Manager, Transmission Control Center shall ensure that personnel conduct calculations using computer models to compute ATC in the following manner:

  4.1.1. Data from the following entities are used in conjunction with PSCo data to calculate ATC:

   - WECC data bank cases (which are comprised of data submitted by WECC members, including Tri-State Generation and Transmission Association.)
   - Western Area Power Administration (TOT studies)
   - Platte River Power Authority (TOT studies)
   - Public Service Company of New Mexico

  4.1.2. The ATC calculation model shall use the equations in Attachment 3.

  4.1.3. When calculating ATC, assumptions shall be no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period.

   - Note - Ensure assumptions (if used) such as contingencies, loop flow, generation re-dispatch, switching operating guides or data sources for load forecast and facility outages are clearly identified and able to be retrieved for verification at a later date.

  4.1.4. Counterflows.

   4.1.4.1. Counterflows are schedules (eTags) which are flowing in the opposite direction of the prevailing ATC Path. Schedules may be flowing on firm or non-firm transmission.

   4.1.4.2. In the Operating and Scheduling Horizons non-firm ATC will include counter flows of schedules (eTags) on all ATC Paths.

   4.1.4.3. In the Planning Horizon non-firm ATC will not include any counterflow schedules with the excepton of the Lamar DC Tie. For all other ATC Paths, counterflows will assumed to be zero.

   4.1.4.4. Firm ATC will never include counterflow schedules.

  4.1.5. Allocate ATC as follows:

4.1.5.1. IF more than one line comprises an ATC path, THEN allocate the ATC to the entire set of lines as a whole.

4.1.5.2. IF there are multiple owners of an ATC path, THEN allocate ATC according to contractual arrangements.

4.1.5.3. IF there are concerns raised regarding forward-looking congestion management, seams coordination, or other issues as identified by the TSP or other TSPs, THEN the Manager, Transmission Control Center shall coordinate with the RTP group to determine if a change to the methodology or process within the methodology should be included to handle those concerns within the calculation and allocation.

4.1.6. Include planned generation and transmission outages, consistent with those reported in the Control Room Operation Window (CROW)) (which includes partial day, and partial month outages) into the model that computes the ATC values.

4.1.6.1. IF there are outages from other TSPs that cannot be mapped to the model used to calculate ATC, THEN the Manager, Transmission Control Center shall coordinate with the RTP group to determine if a manual adjustment is required in the model to account for the outage.

4.2. ATC values shall be calculated for the following time increments:

4.2.1. Hourly values for at least the next 48 hours.

4.2.2. Daily values for at least the next 31 calendar days.

4.2.3. Monthly values for at least the next 12 months (months 2-13).

4.3. ATC values shall be calculated for at the following frequencies (unless none of the values in the ATC calculation have changed):

4.3.1. Hourly values, once per hour.

4.3.2. Daily values, once per day.

4.3.3. Monthly values, once per week.

5. Administration

5.1. Providing Data to other TOPs and TSPs for ATC Calculation Purposes

5.1.1. PSCo provides data for ATC calculation purposes to:

- Platte River Power Authority
- Western Area Power Administration
- WECC (to populate data bank base cases)

5.1.2. IF a TOP or TSP not listed above desires data for ATC calculation purposes, THEN contact the Manager, Transmission Control Center at the address or phone number listed in step 5.4.1.

5.2. Availability of ATCID

5.2.1. The Manager, Transmission Control Center shall ensure the ATCID is posted on PSCo's OASIS website.

5.2.2. IF an entity cannot access the PSCo website, THEN contact the Manager, Transmission Control Center at the address or phone number listed in step 5.4.1 to obtain a direct copy or get instructions on how to get access to the PSCO OASIS website.

5.3. Distribution of proposed changes to the ATCID

5.3.1. The Manager, Transmission Control Center will notify the entities in Attachment 5 of proposed changes to the ATCID prior to the proposed effective date.

5.3.2. IF an entity has concerns regarding changes to the ATCID, THEN contact the Manager, Transmission Control Center at the address or phone number listed in step 5.4.1 prior to implementation. Concerns regarding the ATCID after the effective date of changes may be conveyed to the Manager, Transmission Control Center as explained in 5.4.1, however, those concerns may not be addressed before the next scheduled review of this procedure, at the discretion of the Manager, Transmission Control Center.

5.3.3. The Manager, Transmission Control Center, shall provide the entities identified in Attachment 5 with a final version of the ATCID after comments from affected entities are addressed and internal approval has been obtained The final approved ATCID shall then be posted on PSCo's OASIS site in accordance with 5.2.1.

5.4. Sharing of Data Used to Determine ATC

5.4.1. Requests for the data supporting ATC calculations shall be directed to the Manager, Transmission Control Center at the address or phone number listed below.

Phone Number:

303-273-4797

Mailing Address:

Manager, Transmission Control Center (PSCo)

Attn: ATC Data Request

18201 West 10th Ave.

Golden, CO, 80401

5.4.2. Requests are permitted from:

5.4.2.1. Transmission Operators (TOPs), Transmission Service Providers (TSPs), Reliability Coordinators (RCs), or Planning Coordinators (PCs).

5.4.3. Data requests for up to 13 months into the future are permitted on the items in Attachment 4.

5.4.4. The Manager, Transmission Control Center shall begin to provide the information, within 30 days of receiving the request.

5.4.5. The data shall be made available on the schedule specified by the requestor (not more frequently than once per hour, unless mutually agreed by the requestor and PSCo).

5.4.6. The data shall be made available by one of the two methods (or any alternative mutually agreed upon method):

- posting to a website or location from which the requestor will be able to obtain the data
- direct transfer of the data (e.g. email)

5.5. The Manager, Transmission Control Center shall ensure personnel track the cumulative hours that hourly values are not calculated but that a change in the calculated value identified in the ATC equation occurred. (Note – the MOD-001-1 standard permits up to 175 hours of no calculation before a violation limit is reached)

5.6. Document Retention

5.6.1. Requests for ATC data and communications regarding proposed ATCID changes shall be retained as evidence of compliance with the applicable NERC Standards.

5.7. Availability of TTC Study Report and TTC Values

5.7.1. IF a TSP desires a copy of the TTC study and the TTC values, THEN contact the Manager, Transmission Control Center at the address or phone number listed in step 5.4.1.

Attachment 1

TTC Model Criteria

The following describes the TTC model criteria. The model shall:

1. Include at least:
   - The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.
   - All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)
   - Any other Transmission Operator area linked to the Transmission Operator's area by a joint operating agreement. (Equivalent representation is allowed.)
   - Models all system Elements as in-service for the assumed initial conditions.
   - Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.
   - Models phase shifters in non-regulating mode, unless otherwise specified in this procedure.
   - Uses Load forecast by Balancing Authority.
   - Uses Transmission Facility additions and retirements.
   - Uses Generation Facility additions and retirements.
   - Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon.
   - Models series compensation for each line at the expected operating level unless specified otherwise in this procedure.
   - Includes any other modeling requirements or criteria specified in this procedure.

2. Use Facility Ratings as provided by Transmission Owner and Generator Owners.

Attachment 2

ETC Equations

$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$

NL_F is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$NITS_F$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_F is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID. This includes the use of forecasted generation values for Native Load as described in PSCo's General Business Practices.

Attachment 3

ATC Equations

$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$

ATC_F is the firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

$Postbacks_F$ are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_F$ are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in the ATCID.

$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$

ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that

period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

ETC_{NF} is the sum of existing non-firm commitments for the ATC Path during that period.

CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

$Postbacks_{NF}$ are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_{NF}$ are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in the ATCID.

Attachment 4

Data That Can Be Provided Upon Request

Refer to the body of this procedure regarding the process for requesting the following information. The MOD-001-1 Standard specifies:

> R9.1.1. If the Transmission Service Provider uses the data requested in its transfer or Flowgate capability calculations, it shall make the data used available.
>
> R9.1.2. If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, but maintains that data, it shall make that data available.
>
> R9.1.3. If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, and does not maintain that data, it shall not be required to make that data available.

- Expected generation and Transmission outages, additions, and retirements.
- Load forecasts.
- Unit commitments and order of dispatch, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:
  - Dispatch Order
  - Participation Factors
  - Block Dispatch
- Aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (i.e. Secondary Service).
- Firm and non-firm Transmission reservations.
- Aggregated capacity set-aside for Grandfathered obligations
- Firm roll-over rights.
- Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts.
- Power flow models and underlying assumptions.
- Contingencies, provided in one or more of the following formats:
  - A list of Elements
  - A list of Flowgates
  - A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider
- Facility Ratings.
- Any other services that impact Existing Transmission Commitments (ETCs).
- Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) for all ATC Paths.

- Values of TTC and ATC for all ATC Paths for those Transmission Service Providers receiving the request that do not consider Flowgates when selling Transmission Service.
- Source and sink identification and mapping to the model.

Attachment 5

Entities to be Notified Prior to ATCID Changes

NERC Reliability Standard MOD-001-1a requires that the Transmission Operator make available its ATCID to certain parties listed in the standard.

The list below are the entities identified that shall receive notification (Prior to the effective date) when changes to the ATCID are proposed. (Identified in the NERC Registry 8/11/2017)

Entity	email	Within PSCo	Neighbor	TOP	TSP	TP	RC	PC (PA)
Public Service Company of Colorado Updated: 12/10/2019	Bob Staton Manager, Transmission Control Center (PSCo) 18201 West 10th Ave. Golden, CO, 80401 Office: 303-273-4797 Robert.staton@xcelenergy.com Claire Van Gundy Senior Engineer 18201 West 10th Ave. Golden, CO, 80401 Office: 303-273-4654 Claire.VanGundy@xcelenergy.com	X		X	X	X		X
Southwestern Public Service Company	Kyle McMenamin Manager, Transmission Control Center (SPS) Office: 806-640-6306 Kyle.McMenamin@xcelenergy.com		X	X		X		
Tri State Generation & Transmission Association Updated: 12/10/2019	Igor Kormaz Operations Support Manager Office: 303-254-3493 ikormaz@tristategt.org Mary Ann Zehr Senior Manager Transmission Contracts, Rates, and Policy Office: 303-254-3098 mzehr@tristategt.org Shannon Bernard OASIS/OATT Administrator Office: 303-254-3576 sbernard@tristategt.org	X	X	X	X	X		
Platte River Power Authority Updated: 12/12/2019	Matthew Thompson Systems Operations Compliance Specialist and OASIS Administrator Cell: (970) 219-7617 thompsonm@prpa.org	X	X	X	X	X		X

	Derek Book System Operations Compliance Specialist Office: 970-229-5391 bookd@prpa.org							
Western Area Power Administration – Rocky Mountain Region AND Western Area Power Administration – Desert Southwest Region Updated: 01/13/2020	Jonathon W. Steward Transmission Business Unit Manager Western Area Power Administration/Rocky Mt. Region Office: 602-605-2774 Steward@WAPA.GOV Raymond Vojdani Transmission Policy Advisor Western Area Power Administration/Rocky Mt. Region Office: 970-641-7379 avojdani@wapa.gov Brent Session Sessions@WAPA.GOV Steve Robinson Srobinson@WAPA.GOV		X	X	X	X		X
Public Service Company of New Mexico Updated: 12/10/2019	Don Lacen Manager, Compliance Operations Public Service Company of New Mexico Alvarado Square - MS EP11 Albuquerque, NM 87158 Office: 505 241-2409 dlacen@pnm.com Karen Reedy Transmission Planning Office: 505-241-4591 PNMTransPlanCompliance@pnmresources.com		X	X	X	X		X
Black Hills Colorado Electric Updated: 12/10/2019	Dan Kline Director of Transmission Services Office: 605-721-1396 Dan.Kline@blackhillscorp.com Eric M. East Manager, Tariff and Contract Administration Office: 605-721-2261 Eric.East@blackhillscorp.com	X		X	X	X		
Colorado Springs Utilities Updated: 12/10/2019	Warren Rust Operations Superintendent Office: 719-668-4128 rrust@csu.org Jeff Hanson Transmission Planning Engineer jhanson@csu.org		X	X	X	X		X

Intermountain Rural Electric Association Updated 1/3/2020	Pamela (Pederson) Feuerstein, PE Chief Operating Officer P.O. Drawer A 5496 North U.S. Highway 85 Sedalia, CO 80135 Office: 720-733-5489 PFeuerstein@irea.Coop Andy Minter Transmission Operations Manager Office: 720-733-5578 aminter@irea.coop	X		X				
Southwest Power Pool Updated: 1/13/2020	CJ Brown Director, SPP Operations Office: 501-614-3569 cbrown@spp.org Yasser Bahbaz Manger, Reliability Office: 501-688-1607 ybahbaz@spp.org OpsAFCEng@spp.org	X			X	X	X	X
California Independent System Operator Updated: 1/13/2020	Procedure Control Desk procctrldesk@caiso.com Ops Planning South Ops-Planning-South@caiso.com		X		X	X	X	X

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Attachment 6

NERC Director of Enforcement grants extension of time for MOD-029-1 R2.1

http://www.nerc.com/docs/compliance/MOD-029%20letter-AJR%202011MAR03.pdf

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

March 4, 2011

To Transmission Owners and Transmission Service Providers subject to MOD-029-1:

On February 24, 2011, a number of registered entities with in the Western Interconnection (the "WestConnect Utilities") submitted to NERC and to WECC a request for extension of time to comply with Reliability Standard MOD-029-001. This request follows efforts by the WestConnect Utilities to seek an extension of time from FERC, which was recently dismissed.[1] In its dismissal order, FERC ruled that "requests for extension should be considered through NERC's enforcement and compliance program."[2] In exercise of that authority, I am granting an extension of time as detailed below for all entities subject to MOD-029-1 R2.1 as that requirement is applied to "Flow Limited" paths.

Following the review of the WestConnect Utilities' recent filing with FERC and a thorough investigation by NERC and WECC of the concerns being raised by these entities, NERC has determined there to be a valid technical concern with the MOD-029-1 Reliability Standard (Rated System Path Methodology). This concern has the potential to affect any entities that have chosen to implement MOD-029-1 to some degree; the magnitude will depend on the unique characteristics of the applicable entity's system.

NERC understands that the current MOD-029-1 methodology may, in certain cases, lead to Total Transfer Capability (TTC) and Available Transfer Capability (ATC) values significantly lower than those previously used. MOD-029-01 Requirement 2, Sub-Requirement 2.1 requires the use of a simulation to determine the TTC:

> R2.1. Except where otherwise specified within MOD-029-1, adjust base case generation andLoad levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:

When the simulation identifies a limiting piece of equipment that restricts the amount of flow on a path, that path is considered "Reliability Limited," and the TTC is set based on that flow. When the simulation cannot sufficiently load the transmission path such that a limit is

[1] Docket No. RM08-19-00 – "Request for Extension of Compliance Date and Request for Expedited Consideration of the WestConnect Utilities" (December 30, 2010); *Order Dismissing Request for Extension*, 134 FERC ¶ 61,118 (February 17, 2011).
[2] *Id.* at P. 12.

116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

encountered, the path is referred to as being "Flow Limited." Currently, by virtue of requiring the TTC to be established based on the simulation, MOD-029 R2.1 seems to indicate the TTC should be established as the maximum flow simulated for those "Flow Limited" paths. Because of the inconsistencies between contract path scheduling and actual flows on the system, however this can result in cases where TTC is artificially constrained below what the system can actually accommodate. Setting the TTC equal to the maximum simulated flow and then using it to analyze contract-path schedules will not accurately account for parallel path flows and counterflows. Consequently, paths affected by parallel path flows and/or counterflows may have their ATC reduced to some degree. In examples provided to NERC by the WestConnect Utilities, there have been cases where TTCs have reduced by more than 75%.

While this appears to be primarily a commercial issue, the WestConnect Utilities have indicated that strict enforcement of the standard may cause a reliability impact on those entities that depend on the use of the transmission system to serve load. In any event, as a general principle, NERC works to ensure that NERC Reliability Standards do not cause undue restrictions or adverse impacts on competitive electricity markets.

Given the short amount of time remaining until the effective date of April 1, 2011, NERC advises all transmission owners and transmission service providers that have selected the MOD-029-1 methodology that, while they are still expected to be compliant with the standard on April 1, 2011, NERC will be delaying the implementation of MOD-029-01 Requirement 2, Sub-Requirement 2.1 for "Flow Limited" paths only, until such time as a modification to the standard can be developed that will mitigate the technical concern identified. While this request for an extension arose within the Western Interconnection, this delay in implementation for MOD-029-01, Sub-Requirement 2.1 will be available to any transmission owner or transmission service provider that chose the MOD-029-1 methodology, regardless of where located.

NERC is working with a group of industry technical experts to develop a SAR and suggested modifications to the standard. It is expected that such a modification will be consistent with current practices used today, and that the modification would be approved and filed within the next 5-8 months. NERC will also be working with its stakeholders to analyze the aforementioned inconsistencies between contract-path scheduling and actual flows on the system to determine if a longer-term solution is required.

In the interim, NERC suggests (but does not require) that entities calculate the TTC of "Flow Limited" paths consistent with practices used in the past (such as using the path thermal rating). During audits, any paths for which TTC has not been calculated based on R2.1 will be expected to be demonstrably "Flow Limited." Evidence to demonstrate this will be considered on a case by cases basis, but in general, a presentation of the studies showing the results of the simulation will be adequate proof of compliance.

NERC emphasizes that with the specific exception of the implementation of MOD-029-1 R2.1 on "Flow Limited" paths, all applicable entities are expected to proceed with their implementation plans for the ATC-related MOD standards. If any registered entity believes that it cannot meet the April 1, 2011 effective date for any of the other requirements in the ATC-related MOD standards, the entity should self report possible violations and develop and file mitigation plans covering each requirement of the applicable MOD standards for which the entity will not be in compliance on the effective date. NERC encourages such entity to coordinate with its regional entity so that it can be prepared in anticipation of timely self-reporting by the effective date.

Joel deJesus
Director of Enforcement

cc: Connie White (WECC)
Jonathan First (FERC)
Thomas Loquvam
Blane Taylor
Amy Welander
Margaret Rostker
Douglas Harness
Kelly Barr
Ronald Moulton
Jim McMorran
Stephen Keene
Dennis Malone
David Zimmermann
James Burson

1.0 PURPOSE

- This document serves to promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations. Steps in this procedure are used to meet the requirements of the MOD-004-1 NERC Reliability Standard (and subsequent versions).

- CBM is defined in the NERC Glossary as:

  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. Preservation of CBM for an LSE 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 LSE only in times of emergency generation deficiencies.

2.0 APPLICABILITY AND RESPONSIBILITIES

- Manager, Transmission Control Center – responsible for acting as the point of contact and managing the CBM processes.

- Manager, Real Time Planning Engineering – responsible for assisting in the review of CBM set aside requests; responsible for determination of CBM values to be used by the PSCo Transmission Service Provider.

- Manager, Transmission Planning – responsible for assisting in the review of CBM set aside requests; responsible for determination of CBM values to be used for transmission planning.

- Transmission Control Center Operators – responsible for administering the steps for use of CBM.

- Load Serving Entities (LSEs), Resource Planners (RPs) – responsible for making requests and providing information as indicated in this procedure when requesting CBM set aside or requesting use of CBM.

3.0 APPROVERS

Name	Title
Robert Staton	PSCo Control Center Manager
Dean Schiro	Manager, Real Time Planning Engineering

Betty Mirzayi	Manager, Transmission Planning (PSCo)

4.0 VERSION HISTORY

Date	Version Number	Change
Effective 4/1/2011	1.0	Initial version – created as part of MOD-004-1 implementation
10/31/14	2.0	Updated approver list. Updated titles. Updated attachment 1 contact list

Methodology

1. Transmission Capacity Set Aside Request Process

1.1. Load Serving Entities (LSEs) and Resource Planners (RPs) within the PSCo Balancing Authority Area that need Transmission capacity to be set aside as CBM shall:

1.1.1. Determine their need for CBM based on one or more of the following methods to determine the Generation Import Capability Requirement (GCIR).

- Loss of Load Expectation (LOLE) studies.
- Loss of Load Probability (LOLP) studies.
- Deterministic risk-analysis studies.
- Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities.

1.1.2. Identify the expected import path(s) or source region(s).

1.1.3. Identify the desired time frame (start, end) for the need.

1.1.4. Provide the technical point of contact for the requesting entity (name, phone number, email address)

1.1.5. Provide information from steps above, at least 60 days prior to the desired start time, to the following point of contact at the PSCo Transmission Service Provider (TSP) via the address below or contact the Manager, Transmission Control Center for an email address to send the request:

Phone Number:

303-273-4797

Mailing Address:

Manager, Transmission Control Center (PSCo)

Attn: CBM Request

18201 West 10th Ave.

Golden, CO, 80401

2. Establishing CBM

- Note – Prior to MOD-004-1 effective date, PSCo maintained a value of zero (“0”) CBM. Until a CBM set aside request is received pursuant to Section 1 and a CBM value is established per Section 2, a CBM value of zero (“0”) value will be established for all ATC import paths.

2.1. Upon receipt of a Transmission capacity set aside request, the Manager, Transmission Control Center will coordinate with Real Time Planning Engineering (RTPE) and Transmission Planning (TP) to review the request to determine the amount of Transmission capacity that can be set aside to accommodate the requestor’s needs.

2.1.1. RTPE or TP shall contact the requestor to review the basis and parameters for their request.

2.1.2. The analysis shall include a review of the requestor’s assumptions and studies (including, but not limited to, reserve margin or resource adequacy requirements) used to determine the Generation Capability Import Requirement (GCIR).

2.1.3. The analysis may include factors such as existing ATC, for the requested import path.

2.2. Based on the analysis by RTPE or TP, the Manager, Transmission Control Center will establish a CBM value for ATC import path(s). (Note - this value may be zero for some or all of the paths).

2.2.1. The Manager, Transmission Control Center will contact the requestor and discuss the proposed CBM values.

2.2.2. IF there is disagreement on the proposed CBM values, THEN a review between the requestor and the Manager, Transmission Control Center shall be held to determine if any adjustments to the studies or assumptions should occur.

2.2.3. The CBM values shall be allocated based on the expected import paths or source regions provided by the requestor

2.2.4. The CBM values shall be determined by RTPE for 13 full calendar months (months 2 -14) following the current month (month in which value is determined).

2.2.4.1. These values will be used in the calculation of ATC.

2.2.5. The CBM values shall be determined by TP for 13 full calendar months (years 2 -10) following the current year (year in which value is determined).

2.2.5.1. These values will be used in planning.

2.2.6. The CBM values will be determined at least every 13 months.

2.3. Within 31 days after establishing or revising CBM values, the Manager, Transmission Control Center will notify all LSEs and RPs that requested CBM Transmission capacity to be set aside, the amount of CBM set aside.

2.3.1. CBM values will also be posted on the PSCo Open Access Same Time Information System (OASIS).

3. Use of CBM

3.1. Energy Deficient Entities (LSEs or BAs) requesting the use of CBM shall:

3.1.1. Request and receive a NERC Energy Emergency Alert (EEA) 2 or higher status.

3.1.2. Use a valid OASIS CBM reservation number in the Request for Interchange.

3.2. Upon receipt of a Request for Interchange using CBM, the Transmission Control Center operators shall:

3.2.1. Verify the load of the energy deficient entity is within the PSCo Transmission Service Provider area.

3.2.2. Verify the declaration of an EEA 2 or higher by the Reliability Coordinator (RC) for the PSCo Balancing Authority by checking status with the RC via WECCnet or telephone.

3.2.3. Verify that any out of service transmission elements that could provide additional transfer capability are not available to be returned to service

3.2.4. Verify that CBM is available by checking the availability on OASIS

3.2.4.1. IF CBM was reserved as non-firm under the provisions of Section 4 then curtail those transactions as necessary to make CBM available to the Energy Deficient Entity.

3.2.4.2. IF the amount of CBM requested exceed the amount available and established under Section 2, THEN that request will be considered on a case by case basis to include the following factors:

- Additional transfers across the path(s) would not cause a reliability risk
- Concurrence from the WECC RC to allow additional transfers and to suspend, temporarily, scheduling limits
- Firm Arranged Interchange will not be curtailed
- Entities already using the CBM will be contacted to see if some can be released

3.2.5. Evaluate the entity's need to have waived, within the bounds of reliable operation, Real-time timing and ramping requirement. Communication with the Energy Deficient Entity may be needed.

3.2.6. Approve the Arranged Interchange using CBM by the Energy Deficient Entity AFTER meeting steps 3.2.1 through 3.2.5

4. Conditions Under Which CBM May be Available as Non-firm Service

4.1. Transmission capacity set aside as CBM may be release as non-firm service when no EEA2 or higher has been declared for the PSCo Balancing Authority Area.

4.1.1. Unused portions of any CBM, if released as non-firm service, will be available on OASIS.

5. Administration

5.1. Availability of CBMID

5.1.1. The Manager, Transmission Control Center shall ensure the CMBID is posted on PSCo's OASIS website.

5.1.2. IF an entity cannot access the PSCo website, THEN contact the Manager, Transmission Control Center at the address or phone number listed in step 1.1.5 to obtain a direct copy or get instructions on how to get access to the PSCO OASIS website.

5.2. Distribution of proposed changes to the CBMID

5.2.1. The Manager, Transmission Control Center will notify the entities in Attachment 1 of proposed changes to the CBMID prior to the proposed CBMID effective date.

5.2.2. IF an entity has concerns regarding changes to or the content of the CBMID, THEN contact the Manager, Transmission Control Center at the address or phone number listed in step 1.1.5.

5.3. Distribution of CBM values

5.3.1. New or revised CBM values will be conveyed within 31 days under step 2.3 to those LSEs or RPs requesting CBM set aside.

5.4. Sharing of Models and Data Used to Determine CBM

5.4.1. Requests for models, data, and supporting information shall be directed to the Manager, Transmission Control Center at the address or phone number listed in step 1.1.5.

5.4.2. Requests are permitted from

5.4.2.1. Associated Transmission Operators (TOPs)

5.4.2.2. Transmission Service Providers (TSPs), Reliability Coordinators (RCs), Transmission Planners (TPs), Resource Planners (RPs), or Planning Coordinators (PCs).

5.4.3. The Manager, Transmission Control Center shall provide copies of the requested data, subject to confidentiality and security requirements, within 30 days of receiving the request.

5.5. Document Retention

5.5.1. Request for CBM set aside, communications regarding proposed CBMID changes, and communications regarding established or revised CBM values shall be retained as evidence of compliance with the applicable NERC Standards.

Attachment 1

Entities to be Notified Prior to CBMID Changes

NERC Reliability Standard MOD-004-1 requires:

> R2. The Transmission Service Provider that maintains CBM shall make available its current CBMID to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, Resource Planners, and Planning Coordinators that are within or adjacent to the Transmission Service Provider's area, and to the Load Serving Entities and Balancing Authorities within the Transmission Service Provider's area, and notify those entities of any changes to the CBMID prior to the effective date of the change.

The list below are the entities identified that shall receive notification (Prior to the effective date) when changes to the CBMID are proposed. (Identified in the NERC Registry 2/17/2011)

Entity	**email**	**Within PSCo**	**Neighbor**	**TOP**	**TSP**	**TP**	**RC**	**RP**	**PC (PA)**	**LSE**	**BA**
Public Service Company of Colorado	Bob Staton Manager, Transmission Control Center (PSCo) 18201 West 10th Ave. Golden, CO, 80401 Robert.staton@xcelenergy.com 303-273-4797 Robert K Johnson Principal Engineer 18201 West 10th Ave. Golden, CO, 80401 Robert.k.johnson@xcelenergy.com 303-273-4893	X		X	X	X		X	X	X	X
Southwestern Public Service Company	Kyle McMenamin Manager, Transmission Control Center (SPS) 806-640-6306 Kyle.McMenamin@xcelenergy.com		X	X	X	X		X		X	X
Tri State Generation & Transmission Association	Doug Reese, Operations Support Manager 303-254-3676 dreese@tristategt.org Mark Riley Reliability Compliance Specialist 303-254-3143 marril@tristategt.org	X	X	X	X	X		X		X	
Platte River Power Authority	John Collins System Planning Manager 970-229-5272 collinsj@prpa.org Derek Book System Operations Compliance Specialist	X	X	X	X	X		X	X	X	

	970-229-5391 bookd@prpa.org										
Western Area Power Administration – Rocky Mountain Region AND Western Area Power Administration – Desert Southwest Region	Mike McElhany Manager, Transmission Business Unit 602-605-2662 MCELHANY@wapa.gov Patrick Harwood Reliability Compliance Specialist 602-605-2883 Harwood@wapa.gov		X	X	X	X			X		X
Public Service Company of New Mexico	Jeff Mechenbier Director Transmission Analysis Public Service Company of New Mexico Alvarado Square - MS 0604 Albuquerque, NM 87158 work: 505-241-4582 jeff.mechenbier@pnm.com Don Lacen Transmission Services Coordinator Public Service Company of New Mexico Alvarado Square - MS EP11 Albuquerque, NM (505) 241-2032 dlacen@pnm.com		X	X	X	X		X	X	X	X
Black Hills/Colorado Electric Utility Company, LP	Eric Egge Mgr Transmission Planning (605) 721-2646 Eric.Egge@blackhillscorp.com	X		X	X	X		X		X	
Colorado Springs Utilities	Warren Rust Operations Superintendent 719-668-4128 rrust@csu.org Paul Morland Principal Engineer - Operations 719-668-4159 pmorland@csu.org Cliff Berthelot Principal Engineer - Planning 719-668-8091 cberthelot@csu.org		X	X	X	X		X	X	X	X
Holy Cross Energy	David Bleakley Holy Cross Energy Senior Manager, Engineering Department 3799 Highway 82 Glenwood Springs, CO 81602 970-947-5449 dbleakley@holycross.com Diana Golis	X								X	

	Holy Cross Energy Manager, Power Supply and Contracts 3799 Highway 82 Glenwood Springs, CO 81602 970-947-5471 dgolis@holycross.com										
Peak Reliability	RCDESK@peakrc.com Don Pape, Compliance Manager Peak RC Vancouver, WA (360) 713-9586						X				
Southwest Power Pool	Don Shipley Manager, SPP Reliability Coordination Office 501-614-3581 Cell 501-350- 0433 E-mail dshipley@spp.org		X		X	X	X		X		

1.0 PURPOSE

- This document serves to promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations. Steps in this procedure are used to meet the requirements of the MOD-008-1 NERC Reliability Standard (and subsequent versions).

- TRM is defined in the NERC Glossary as:

  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.

2.0 APPLICABILITY AND RESPONSIBILITIES

- Manager, Transmission Control Center – responsible for acting as the point of contact and managing the TRM processes; represents the PSCo Transmission Operator (TOP) and Transmission Service Provider (TSP) functions.

- Manager, Real Time Planning Engineering – responsible for assisting in the determination and calculation of TRM.

- Manager, Transmission Planning – responsible for representing the PSCO Transmission Planner (TP) function.

3.0 APPROVERS

Name	Title
Robert Staton	PSCo Control Center Manager
Dean Schiro	Manager, Real Time Planning Engineering
Connie Paoletti	Manager of Transmission Planning (PSCo)

4.0 VERSION HISTORY

Date	Version Number	Change
Effective 4/1/2011	1.0	Initial version – created as part of MOD-008-1 implementation
10/31/2014	2.0	Moved to Methodology folder from Procedures. Updated approvers and titles.
9/3/2019	3.0	Changed to reflect going from Rocky Mountain Reserve Sharing Group (RMRG) to Northwest Power Pool (NWPP)
6/1/2021	4.0	Changed 1.2.2.2 and 1.2.2.3 to reflect changes made to

		OATT Attachment C, Section 2.g.i and ii

Methodology

1. Establishing TRM Values

1.1. The Manager, Transmission Control Center shall coordinate with the Real Time Planning Engineering group to establish values for TRM.

1.2. Establish TRM values as follows:

1.2.1. ONLY the following components of uncertainty may be included in the TRM value determination. The following apply to all ATC paths for which a TRM value is determined:

Uncertainty Component	PSCo Treatment
Aggregate Load forecast.	Not used.
Load distribution uncertainty.	Not used.
Forecast uncertainty in Transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages).	Not used.
Allowances for parallel path (loop flow) impacts.	Not used.
Allowances for simultaneous path interactions.	Not used.
Variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation).	Not used.
Short-term System Operator response (Operating Reserve actions).	Not used.
Reserve sharing requirements.	Included, based upon the Northwest Power Pool (NWPP) requirements, which change from time to time.
Inertial response and frequency bias.	Not used.

1.2.2. TRM will be determined using the same calculation for same day and real-time, day ahead and pre-schedule, and beyond day-ahead and pre-schedule (up to 13 months ahead).

1.2.2.1. Capacity Benefit Margin (CBM) shall not be included in TRM determination.

1.2.2.2. The TRM is calculated by conducting model simulations to establish the TRM. The following data is used in the calculation:

- The applicable entities reserve response requirements, as described by the NWPP's Program Documentation and supporting information
- the most recent power flow WECC base case for the upcoming season being evaluated

1.2.2.3. Conduct power flow cases, simulating a trip of (1) the largest single hazard in the PSCo Balancing Authority (BA) and (2) the largest PSCo response to a single hazard amongst PSCo's Level 1 responders.

- In each case the NWPP Members' response quotas are modeled for the respective unit loss.

1.2.2.4. The results of the simulations shall establish the allocation of TRM on various paths to account for the reserve delivery across the transmission network

1.3. TRM values will be determined at least once every 13 months.

1.4. Within 7 days after establishing or revising TRM values, the Manager, Transmission Control Center shall provide the TRM values to the Transmission Service Provider and Transmission Planner.

2. Administration

2.1. Availability of TRMID

2.1.1. The Manager, Transmission Control Center shall ensure the TRMID is posted on PSCo's OASIS website.

2.1.2. IF an entity cannot access the PSCo website, THEN contact the Manager, Transmission Control Center at the address or phone number listed in step 2.3.1 to obtain a direct copy or get instructions on how to get access to the PSCO OASIS website.

2.2. Distribution of TRM values

2.2.1. New or revised TRM values will be conveyed within 7 days under step 1.4 to the Transmission Service Provider and Transmission Planner.

2.3. Sharing of TRMID and underlying documentation

2.3.1. Requests for the TRM, and underlying documentation shall be directed tothe Manager, Transmission Control Center at the address or phone number listed below.

Phone Number:

303-273-4797

Mailing Address:

Manager, Transmission Control Center (PSCo)

Attn: TRM Request

18201 West 10th Ave.

Golden, CO, 80401

2.3.2. Requests are permitted from

2.3.2.1. Transmission Operators (TOPs), Transmission Service Providers (TSPs), Reliability Coordinators (RCs), Transmission Planners (TPs), or Planning Coordinators (PCs).

2.3.3. The Manager, Transmission Control Center shall provide the information, in the format used by the PSCo Transmission Operator, within 30 days of receiving the request.

2.4. Document Retention

Request for TRM documentation, and communications regarding established or revised TRM values shall be retained as evidence of compliance with the applicable NERC Standards.

Transmission	
Xcel Energy	Public Service Company of Colorado
PSCo Planning Authority SOL Methodology	**Version: 3.0**
File Name : Appendix P - PSCo Planning Authority SOL Methodology(116592648.1).doc	**Page 1 of 18**

1.0 Purpose:

The North American Electric Reliability Corporation (NERC) Standard FAC-010-3 requires that each Planning Authority "shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Planning Authority Area" and that the methodology "be applicable for developing SOLs used in the planning horizon". In addition, the methodology should "state that SOLs shall not exceed associated Facility Ratings" and the methodology should "include a description of how to identify the subset of SOLs that qualify as IROLs". This document describes the methodology for determining System Operating Limits (SOL) used in the planning horizon for Public Service Company of Colorado (PSCO) Planning Authority Area. Appendix A of the document includes the TTC methodology for the TOT7[1] Transfer Path.

2.0 Applicability and Responsibilities:

The Manager, Transmission Planning (PSCO) is responsible for reviewing and updating this document annually to ensure PSCO's SOL methodology is properly documented and conveyed to the applicable parties.

3.0 Approvers:

Name	Title
Amanda King Huffman	Director, Strategic Transmission Planning
Connie Paoletti	Manager, Transmission Planning

4.0 Version History:

Effective Date	Version Number	Supersedes	Change
10/21/2021	3.0	2.0	Identifies SPP as the new Reliability Coordinator (RC). Contingency categories changed to match language and performance requirements in TPL-001-4. The part of the notification process requiring outside entities to review the document and provide revisions was deleted due to the retirement of R5.

[1] The "TOT7 Transfer Path" (WECC Path 40) is a Western Electricity Coordinating Council (WECC)-defined power transfer path that is comprised of transmission lines that allow power to be transferred between northeast Colorado and the north Denver Metro Area. The path is jointly owned by PSCO and Platte River Power Authority. The path consists of the Ault-Windsor 230 kV line, the WeldPS-Ft.St.Vrain 230 kV line, and the Longs Peak-Ft.St.Vrain 230 kV line. A description of the path is provided in Appendix A.

12/16/2014	2.0	1.0	The revision includes the addition of a procedure for releasing a revised SOL Methodology. The document was also reformatted to make the document easier to review. The “TOT7 SOL Methodology” was changed to a “TOT7 TTC Methodology” and placed in an Appendix to this document..
11/27/2013	1.0	N/A	This document replaces the BES and TOT7 SOL Methodology document that was created in July 2013 that replaced the PSC-PRO_TOT7_SOL_Methodology document that was created in 2008. This document provides a more general description of PSCO’s SOL methodology.

5.0 Definitions:

This document includes standard definitions from the NERC Glossary of Terms Used in Reliability Standards that are included in the following table:

Acronym	Continent-wide Term	NERC Definition
SOL	System Operating Limit	The value (such as MW, MVAR, Amperes, Frequency, or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: * Facility Ratings (Applicable pre- and post- Contingency equipment or facility ratings) * Transient Stability Ratings (Applicable pre- and post- Contingency Stability Limits) * Voltage Stability Ratings (Applicable pre- and post- Contingency Voltage Stability) *System Voltage Limits (Applicable pre- and post- Contingency Voltage Limits)
IROL	Interconnection Reliability Operating Limit	System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Bulk Electric System.
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 transmissions lines (or paths) between those areas under specified system conditions.

6.0 Planning Authority SOL Methodology for the Planning Horizon

The Planning Authority (PSCO) regards the Facility Ratings of its Bulk Electric System (BES) Transmission Facilities as System Operating Limits (SOL). The SOLs are equal to the Facility Rating applicable to each Transmission Facility and hence PSCO SOLs do not exceed the associated facility ratings (R1.2). The Facility Ratings established by PSCO Transmission Owner in accordance with FAC-008 are periodically updated, and each revision is communicated to all applicable entities noted in section 8.0 below.

PSCO as Planning Authority performs studies to evaluate the performance of BES transmission facilities for its annual transmission planning assessment. In performing these studies, PSCO adheres to applicable NERC Reliability Standards, applicable WECC Reliability Criteria, and its own system performance (planning) criteria developed in accordance with TPL-001-5.

PSCO's system performance (planning) criteria is included within its annual transmission planning (TPL-001) assessment report. Further, the annual assessment also includes the following details for all steady-state and dynamic analyses performed, along with any reliability margins applied for each (R3):

- Study model and its level of detail (R3.1, R3.3)
- Selection of applicable Contingencies (R3.2)
- Allowed uses of Remedial Action Schemes (R3.4)
- Anticipated transmission system configuration, generation dispatch and Load level (R3.5)

The studies comprising the annual planning assessment demonstrate that BES performance is consistent with the Planning Event Contingencies defined in TPL-001-5, which in turn demonstrates that the pre-contingency and post-contingency system response (i.e. BES performance) is consistent with R2.1, R2.2, R2.3, R2.4, R2.5, R2.6.

7.0 Determining SOLs that Qualify as IROLs (R3.6)

The Planning Authority conducts studies to determine if pre-contingency and post-contingency disturbances result in instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Bulk Electric System (a potential IROL condition).

A System Operating Limit (SOL) qualifies as an IROL when studies indicate that:

- "impact containment" cannot be adequately demonstrated, or
- instability, cascading, or uncontrolled separation may occur.

"Impact containment" is adequately demonstrated when all the following four items are accomplished:

- the impacted area is pre-defined by studies
- cascading is restrained from sequentially spreading beyond the impacted area
- studies have been coordinated and all concerns resolved for the impacted area that involves more than one PA
- impacted PAs have developed and documented plans, processes, and procedures to ensure adequate containment within the impacted area and have provided this documentation to the RC.

Post transient studies are conducted that identify "thermally limited" IROLs that involve severe loading on a transmission facility due to a contingency that results in a chain reaction of facility disconnection by relay action, equipment failure, or forced immediate manual disconnection of the facility. In general, the thermally limited IROLs are indicated when post-contingency facility loading exceeds 125% (or less if specific protection information is known) of the highest transmission facility rating (emergency rating) followed by subsequent overloading of transmission facilities resulting in cascading outages beyond an area pre-determined by studies. The condition indicates inadequate impact containment. The study involves the following:

- Run the contingency analysis and flag credible contingencies that result in post contingency loading in excess of 125% of the highest facility rating (emergency rating) or the facility relay trip setting if lower.
- For each flagged credible contingency, disconnect both the contingent element(s) that cause the post contingency overload and all subsequent facilities whose post contingency loading is in excess of 125% of the highest facility ratings (emergency rating) or the facility relay trip setting if lower.
- Rerun the power flow analysis
- Identify if there are any facilities whose loading exceeds 125% of the highest facility ratings (emergency rating) or the facility relay trip setting if lower.
- This process is continued until cascading stops or the solution diverges.
- Evaluate the results to identify thermally limited SOLs that qualify as IROLs.

PSCO Planning Authority uses a default IROL T_v of 30 minutes. Shorter duration IROL T_v values may be established in coordination with the impacted PAs, TPs and/or TOPs based on relay/protection settings and other considerations.

8.0 Changes to PSCO Planning Authority SOL Methodology

Any changes to the "PSCO Planning Authority SOL Methodology" are communicated by issuing the revised document to the following entities:

1. Each Planning Authority adjacent to PSCO (in the Western Interconnection) – namely, Black Hills Power Corporation (BHPC), Colorado Springs Utilities (CSU), Platte River Power Authority (PRPA), PacifiCorp East (PACE), and Western Area Power Administration – Rocky Mountain Region (WAPA-RMR).

2. Each Reliability Coordinator that operates any portion of the PSCO Planning Authority Area – namely, Southwest Power Pool (SPP).

3. Each Transmission Operator that operates any portion of the PSCO Planning Authority Area – namely, Intermountain Rural Electric Association (IREA), Holy Cross Energy (HCE), PSCO, Tri-State Generation & Transmission (TSGT), and WAPA-RMR.

4. Each Transmission Planner that works in the PSCO Planning Authority Area – namely, PSCO, TSGT and WAPA-RMR.

APPENDIX A

Path 40 (TOT7) Total Transfer Capability (TTC) Methodology for Calculating the Annual Seasonal Path TTCs

A. TOT7 Total Transfer Capability (TTC) Determination

A.1 TOT7 (Path 40) Transfer Path Definition

The Planning Authority (PSCO) takes responsibility for TOT7 (Path 40). TOT7 is a transfer path recognized by the Western Electricity Coordinating Council (WECC). The TOT7 transfer path (Path 40) is jointly owned with Platte River Power Authority (PRPA). PSCo is the planning authority and path manager for TOT7. PSCo as the planning authority conducts seasonal transmission studies to establish the Total Transfer Capabilities (TTC) for the TOT7 power transfer path.

The TOT7 transfer path is defined as follows:

Transmission Line	Metered End
Ault-Windsor 230 kV	Ault
WeldPS-Fort.St.Vrain 230 kV	WeldPS
Longs Peak-Fort.St.Vrain 230 kV	Fort.St.Vrain

TOT7 (Path 40) is comprised of transmission lines (listed above) that allow power to be transferred between northeast Colorado and the north Denver Metro Area. The path has a maximum north-to-south Total Transfer Capability (TTC) of 890 MW; however, the path TTC is highly dependant on the level of demand in the Foothills Area and the generation level of the Colorado-Big Thompson (CBT) generating units.

A.2 TOT7 TTC Rating Methodology – Study Criteria

Transmission System Planning Performance Number: TPL-001-WECC-CRT-3.2

Each Transmission Planner and Planning Coordinator shall use the following default base planning criteria, unless otherwise specified in accordance with Requirements WR2 and WR3:

1.1. Steady-state voltages at all applicable Bulk-Electric System (BES) buses shall stay within each of the following limits:

1.1.1. 95 percent to 105 percent of nominal for P01 event (system normal pre-contingency event power flow);

1.1.2. 90 percent to 110 percent of nominal for P1-P72 events (post contingency event power flow).

1.2. Post-Contingency steady-state voltage deviation at each applicable BES bus serving load shall not exceed 8 percent for P1 events.

A.3 TOT7 TTC Rating Methodology – Power Flow Studies

The Planning Authority conducts annual studies that pertain to the Western Electricity Coordinating Council (WECC) Power Transfer Path 40 (more commonly referred to a "TOT7") that has its own Total Transfer Capability (TTC). The Planning Authority conducts seasonal studies of the TOT7 transfer path in coordination with the Rocky Mountain Operating Study Group (RMOSG) and the Southwest Power Pool Reliability Coordinator to determine its Transfer Path TTC. The TTC of the TOT7 transfer path depends on the Foothills Area[2] demand and the Colorado-Big Thompson[3] (CBT) generation level. Therefore, the studies consider the impact of varying the Foothills Area demand and the CBT generation on the TOT7 TTC. The study process is as follows:

- A WECC operating case is selected that reflects the operating season that is being studied.
- The operating case is modified by adjusting generation in southeast Wyoming and northeast Colorado with the Stegall/Sidney DC ties importing at 300 MW, CPP (Brush) generation at 71 MW, Pawnee/Manchief/Peetz generation at 810 MW, Rawhide generation at 525 MW, LRS generation at 1210 MW, Dave Johnson generation at 761 MW, Ft.St. Vrain generation at 35 MW with appropriate generation in the WAPA and PSCO balancing authorities to achieve this operating point. Both the TOT7 transfer path flows and the TOT 3[4] transfer path flows are monitored.

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[2] The "Foothills Area" consists of the transmission system in northeast Colorado that is bounded by the Valmont and Henry Lake substations on the south to the Colorado/Wyoming border on the north, and from Estes Park on the west to Greeley on the east.

[3] The "Colorado-Big Thompson Project (CBT)" is a trans-mountain water diversion system that diverts water from the Colorado River headwaters on the western slope to the Big Thompson River, a South Platte River tributary on the eastern slope, for distribution to project lands and communities. Hydroelectric facilities on the Big Thompson River include Big Thompson 4.2 kV No. 1, Estes 6.9 kV No. 1,2 and 3, Mary's Lake Power Plant 6.9 kV No. 1, Pole Hill 13.8 kV No. 1, and Flat Iron 13.8 kV No. 1, 2 and 3. Operating studies conducted by PSCO and Platter River Power Authority has demonstrated that as the CBT generation decreases, the transfer limit of TOT7 decreases.

[4] The "TOT3" Transfer Path (WECC Transfer Path 36) represents the transmission lines that carry the power transfers from southeast Wyoming to northeast Colorado. The path has a maximum north-to-south non-simultaneous rating of 1680 MW. The transfer path owners include the Missouri Basin Power Project (MBPP), Western Area Power Administration-Rocky Mountain Region (Western-RMR), Tri-State Generation and Transmission (Tri-State G&T) and Public Service Company of Colorado (PSCO). The Total Transfer Capability of the TOT3 transfer path is defined by three variable: Laramie River Station (LRS) net generation, the Sidney DC Tie minus Spring Canyon Generation, and the Cheyenne Net Load. The following lines comprise TOT3 - Archer-Ault 230 kV, 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.

- Seventy power flow cases are created that reflect combinations of ten demand levels in the Foothills Area and seven CBT generation levels. The 10 Foothills Area demand levels are developed by scaling the Foothills Area demand starting at 60% of peak and increasing in 5% increments up to 105% of peak demand. A load to resource balance is maintained by dispatching the Rawhide units to cover the changes in the Foothills demand due to PRPA load changes and by dispatching RMEC units to cover the changes in Foothills demand due to PSCO and Tri-State load changes. The RMEC generating station is electrically near the J.M. Shafer and F. Knutson generating stations owned by Tri-State so this RMEC generation dispatch simplification is reasonable. The CBT generation levels are varied in 30 MW increments starting at 0 MW and increasing to 180 MW. The CBT generation changes are balanced using other generating units in the WAPA-RMR area. A TOT7 case is developed for each of the combinations of Foothills Area demand (in 5% increments of peak starting at 60% of peak) comprising ten demand levels and CBT generation (in 30 MW increments starting at 0 MW) comprising seven generation levels, for a total of 10 times seven or 70 scenarios. The Area Interchange in the cases modeled "on"[5] so that the area slack generators in Area 70 and Area 73 maintain a load to resource balance due to changes in losses as generation schedules are varied.
- Each of the 70 TOT7 cases (for a particular combination of Foothills Area Demand and CBT generation level) are obtained so that each case can be re-dispatched to determine the TOT7 TTC for each of the 70 scenarios. To stress each of the 70 scenarios, the transmission system between Wyoming and the Denver Metro Area (that includes the TOT7 path and the TOT3[6] path) is stressed by incrementally increasing north-to-south generation schedules between generating units in Wyoming (or Utah or Idaho if generation is unavailable in the WAPA-RMR area) and generating units in Colorado. At each increment of stressing level, single contingencies (outages of facilities in the study area) are simulated. In addition, the "Ault 2186 Breaker Failure Multiple Contingency" is simulated. The "Ault 2186 Breaker Failure Multiple Contingency" results in the loss of the Ault-Windsor-FSV 230kV line and the Ault-Carey 230kV line. The "Ault 2186 Breaker Failure Multiple

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[5] An alternative method of accomplishing the load the resource balance can be accomplished by leaving Area Interchange On and using Wyoming area generation to cover CBT changes and use generation at locations to the west (western Colorado, Utah, Idaho, Montana, etc) to provide north-to-south stress across TOT7.

Contingency" may limit the TOT7 Total Transfer Capability. This multiple contingency is not deemed an "Always Credible Multiple Contingency"; however, the TOT7 path owners have determined not to take the risk for this event.

- The transmission facilities in the TOT7 study area are monitored for each transfer level and outage condition and line flows and bus voltages for each stressing level and outage condition are captured. The lowest TOT7 flow level for which a transmission element violation just occurs becomes the TOT7 limit for the scenario (one of the seventy combinations of Foothills Area demand and CBT generation level).
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A.4 TOT7 TTC Rating Methodology – Transient and Voltage Stability Studies

Transient Stability Studies - Definition

The objective of a transient stability study is to determine whether or not synchronous machines will return to synchronous frequency following a disturbance. Transient stability analysis examines the system in response to system changes and is used to determine if the system will be stable after a given disturbance. For proper operation of the system, it is essential to ensure that after a given disturbance, the system settles down to a new, stable condition.

Transient Stability Studies - Study Case Development

The transient stability studies are based on the Rocky Mountain Operating Study Group (RMOSG) seasonal base cases. This cases are modified by PSCo to represent the following operating scenarios:

1 Summer 60% of on-peak demand and CBT generation at 180 MW with TOT 7 stressed to the north-to-south Total Transfer Capability (TTC).

2 Summer 60% of on-peak demand and CBT generation at 180 MW with TOT 7 stressed to north-to-south Total Transfer Capability (TTC) (See Item 1 above). The Fort. St. Vrain generation are placed in-service and set to maximum output. This generation is off-set with Comanche generation to help preserve the Eastern Colorado north-to-south transfer level.

3 Summer 105% of on-peak demand and CBT generation at 180 MW with TOT 7 stressed to the north-to-south Total Transfer Capability (TTC).

Transient Stability Studies - Criteria

Transmission System Planning Performance Number: TPL-001-WECC-CRT-3.2

Each Transmission Planner and Planning Coordinator shall use the following default base planning criteria, unless otherwise specified in accordance with Requirements WR2 and WR3:

1.3. Following fault clearing, the voltage shall recover to 80 percent 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.

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

1.5. For Contingencies without a fault (P2.1 category event), voltage dips at each applicable BES bus serving load shall neither dip below 70 percent of pre-contingency voltage for more than 30 cycles nor remain below 80 percent of pre-contingency voltage for more than two seconds.

1.6. All oscillations that do not show positive damping within 30-seconds after the start of the studied event shall be deemed unstable.

WR4. Each Transmission Planner and Planning Coordinator shall use the following threshold criteria to identify the potential for Cascading or uncontrolled islanding. An entity can use these criteria to identify instability due to Cascading or uncontrolled islanding if it does not impose it on others:

• When a post contingency analysis results in steady-state facility loading that is either more than a known BES facility trip setting or exceeds 125 percent of the highest seasonal facility rating for the BES facility studied. If the trip setting is known to be different than the 125 percent threshold, the known setting should be used.

• When transient stability voltage response occurs at any applicable BES bus outside of the criteria stated in Requirement WR1.3 of this document.

• When either unrestrained successive load loss occurs or unrestrained successive generation loss occurs.

Transient Stability Studies – System Response to Disturbances

1. The network data and initial conditions power flow conditions are retrieved from the particular converted power flow case.
2. The power plant models are imported including generator data, turbine-governor data, excitation system (automatic voltage regulator is part of the excitation system), power system stabilizer (PSS), limiters and compensators, turbine load controllers, relays and protection.
3. The initial conditions inside the plant models are determined based on the generator terminal loadings such as generator currents (determined from terminal voltage, real power, reactive power), generator field voltages, electric torque, flux linkages (determined from terminal voltage and current), excitation system conditions (determined from the field voltage, etc.).
4. Excitation system voltage reference and turbine-governor load reference setpoints are initialized.
5. The initial values of the time derivatives of variables are checked to ensure that they are adequately close to zero.
6. A 15-second no disturbance “flat run” simulation is conducted to ensure that quantities do not deviate from the initial conditions.
7. The Ault Substation, Weld Substation, Fort St.Vrain, Rawhide (the critical substations) are evaluated for multiple facility disturbances (common tower and breaker failure) to demonstrate transient stability. All facilities shall be operating within their facility ratings and within their thermal, voltage and stability limits. Cascading outages or uncontrolled separation should not occur.
8. Single-line-to-ground faults with delayed clearing and three-phase faults with normal clearing are performed at critical substations and as part of the large generator interconnection process studies. These include faulted generators, lines, transformers, or shunt devices.
9. Studies involving the loss of any generator, line, transformer, or shunt device without a fault are performed. The TOT7 transfer path does not include any high voltage direct current systems.
10. Single and multiple contingencies are considered as part of the analysis. The simulations include three-phase faults with normal clearing and single-line-to-ground faults with breaker failure and delayed clearing by backup breakers. The analyses use three-phase faults assuming 5-cycle normal clearing time for 230 kV breakers and 4-cycle normal clearing time for 345 kV breakers. The single-line-to-ground breaker failure analyses use backup clearing times provided by PSCo System Protection. Line end faults are applied on the branches connected one bus away from the Ault 345kV, Ault 230kV, WeldPS 230kV and Fort.St.Vrain busses and are cleared by opening the branch.

11. Monitored quantities in the simulations include machine speed deviation and power at the Rawhide and Fort St. Vrain plants and bus voltage and bus frequency at representative busses in the Foothills area.
12. The studies shall demonstrate that all facilities are within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of TTCs, the Bulk Electric System condition used shall reflect expected system conditions and shall reflect changes to system topology such as facility outages. Angle stability studies are conducted to demonstrate transient dynamic stability and that all Facilities are operating within their Facility Ratings and within their limits. No cascading outages into nearby systems should occur. No uncontrolled separations should occur. No generating facilities should lose synchronism. All of the monitored generator relative rotor angles should recover well within the simulation period (15 seconds) and be positively damped. Following fault clearing, bus voltages should recover within required voltage levels and time durations per criteria. Branch flows should be within appropriate system protection settings.
13. The extent of the breaker failure contingencies is determined by the substation configuration and the relative short circuit strengths of each line at the substation of interest. Plots of machine speed, power, and bus voltage for each contingency are produced to perform an assessment. Maximum bus voltage deviations from their pre-fault value are also determined.

<u>Voltage Stability Studies - Definition</u>

Voltage stability is the ability of a power system to maintain acceptable voltages at all buses in the system under normal conditions (system intact) and after a disturbance. A system enters a point of voltage instability when a disturbance, increase in load demand, or change in system conditions causes a progressive and uncontrollable decline in voltage due to the inability of the system to meet the demand for reactive power.

The ability of a power system to maintain voltage stability at all the buses in the system for normal (system intact) and abnormal (outage) conditions is assessed by the creation of “V-Q curves” (Voltage vs. Reactive Power “Q”) and “P-V curves” (Real Power “P” vs. Voltage). The curves show the voltage collapse point of the buses in the power system network. They can be used to find the maximum transfer of power between areas before a voltage collapse occurs. They can also be used to determine the size the reactive power compensation devices required at relevant buses to prevent voltage collapse. They allow the study of the influence of generator, loads and reactive power compensation devices on the network.

A series of ac power flow solutions are used to obtain the P-V and V-Q curves. The P-V curve describes the voltage change as a result of increased power transfer between two subsystems. The V-Q curve describes the reactive power demand by a bus as voltage level changes. V-Q curves are used to determine the reactive power injection required at a bus in order to vary the bus voltage to the required value. The bottom of the V-Q curve, (where the change of reactive power with respect to voltage is equal to zero) represents the voltage stability limit. In TOT7 studies, a minimum voltage set-point of 0.90 p.u. is chosen as voltages lower than this may activate protective devices and because voltages below 85% to 90% of the nominal value could cause some induction motors to stall and draw high reactive current.

<u>Voltage Stability Studies - Criteria</u>

TPL-001-WECC-CRT-3.2—Transmission System Planning Performance

WR5. Each Transmission Planner and Planning Coordinator shall use the following minimum criteria when identifying voltage stability:

5.1. For transfer paths, all P0-P1 events shall demonstrate a positive reactive power margin at a minimum of 105 percent of transfer path flow.

5.2. 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.

5.3. For load areas, all P0-P1 events shall demonstrate a positive reactive power margin at a minimum of 105 percent of forecasted peak load.

5.4. 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.

<u>Voltage Stability Studies - Study Cases</u>

The following cases are used:

a. A summer on-peak demand (105% of peak) case with CBT generation off-line and TOT7 increased to the maximum Total Transfer Capability (TTC).

b. A summer off-peak demand (60% of peak) case with CBT generation at 180 MW and TOT7 increased to the maximum Total Transfer Capability (TTC).

Voltage Stability Studies - Critical Bus Identification

A large number of busses may exist in a study area and to study every bus can be very time consuming. The identification of critical buses to study helps to reduce the amount of study time. There are various methods that can be used to identify critical buses to study. Two such methods are:

1. Single contingencies are simulated using ACCC[7]. The percent voltage deviation at each bus is calculated.

2. The fault MVA at buses in the Foothills Area is calculated with the PSS/E load flow programs using a converted load flow case. The load flow case is converted using "CONL" (real power at 100% constant current and reactive power at 100% constant admittance) , followed by "CONG", and ORDR". A three-phase fault is applied at a particular bus. An inductive reactor of low inductance (high susceptance, i.e. a large "B Shunt" value of "-E+06") is placed at the bus. A "PowerFlow>Solution>FACT" is performed followed by a "PowerFlow>Solution>TYSL". Using PowerFlow>Report>POUT with a "wide format" selected with the output in "amps" for the bus where the fault is applied gives the fault current in MVA and amps. As a "rule of thumb", the change in the voltage at a bus can be determined by taking the net MVAR's entering or leaving a bus divided by the short circuit MVA of the bus.

The study engineer using the first method is looking for the busses with the largest percent voltage deviation for the particular outage as an indication of the critical or "weak" bus. The study engineer using the second method is looking for the busses with the smallest fault MVA as an indication of the critical or "weak" buses.

Voltage Stability Studies - V-Q Analysis (for Reactive Power Studies)

The V-Q curve describes the relationship of bus voltages with respect to reactive power injection or absorption at a bus. The curve shows sensitivities and variations and measures power margins in the system and the reactive power requirement (at 105% of peak demand). PSS/E V-Q analysis software is used to give an indication of the amount of reactive power ("Q") that would need to be generated or absorbed to achieve a particular voltage ("V") at selected buses to determine the amount of reactive power that would need to be generated or absorbed at a bus (in order to attain a desired voltage), each combination of "V-Q" points (reactive power "Q" and bus voltage "V") is obtained through a series of ac power flow calculations. Starting with the specified maximum per unit voltage setpoint at the study bus, the reactive power injections can

[7] "ACCC" is an acronym for "AC Contingency Calculation", a PSS/E software tool.

be computed for a series of power flows as the voltage setpoint is decreased in steps. The V-Q points are generated by artificially introducing a synchronous condenser, with high reactive power limits, at the bus in question. As the scheduled voltage set point (bus voltage) of the bus is varied in steps for a series of ac power flow calculations, the reactive power output from the condenser is monitored. The process entails selecting a bus and allowing the V-Q software to set a voltage and have the artificial synchronous condenser generate or absorb reactive power until the target voltage at the bus being tested is achieved. This is done for the study case (either normal configuration or one of the maintenance outages) and repeated for a subsequent outage of any of the branches (transmission lines or transformers) in the study area. In theory, the process would be repeated until the case no longer solves which is called the "critical voltage" of the V-Q curve where dQ/dV = 0. In practice, the process is discontinued when the bus voltage reaches 0.90 p.u. because voltages lower than this may activate protective devices and because voltages below 85% to 90% of the nominal value could cause some induction motors to stall and draw high reactive current.

The following is the procedure that is followed in the studies as defined by the WECC Voltage Stability Criteria document:

1. Set up a load flow case representing the systems post-contingency condition using a governor load flow.
2. Identify the critical bus in the system for this contingency.
3. Apply a fictitious synchronous condenser at the critical bus.
4. Vary the condenser scheduled output voltage in steps.
5. Solve the load flow case.
6. Record the bus voltage (V) and reactive power output of the condenser (Q)
7. Repeat steps four through six until sufficient points have been collected.
8. Plot the V-Q curve and determine the reactive margin.

V-Q Analysis Solution Options:
Lock taps, disable area interchange control, lock all switched shunts, disallow phase shifter adjustment, disallow DC taps adjustment

Initial (maximum) per unit voltage set-point at the study bus (VHI): 1.10 p.u.
Minimum per unit voltage set-point at the study bus (VLO): 0.90 p.u.
Per unit voltage set-point decrement at the study bus (DLTAV): 0.02 p.u.

<u>Voltage Stability Studies - P-V Analysis (for Real Power Studies)</u>

The P-V curves relates voltage at a bus to load within an area or flow across an interface. Bus voltages are monitored throughout a range of increased load and real power flows into a region. This curve provides an indication of proximity to voltage collapse throughout a range of load levels or interface path flows for the system topology.

P-V curves are developed in the PSS/E software by increasing transfers across the tie lines that define a selected area. The software incrementally increases load within the study area and increases generation externally. The changes in load and generation are accomplished with scaling the increase across the selected area and keeping the load power factors constant. At each load increment, the voltage at the monitored bus is recorded. In theory, the process would be repeated until the case no longer solves which is called the "knee point" of the P-V curve. In practice, the process is discontinued when the bus voltage reaches 0.90 p.u. because voltages lower than this may activate protective devices and because voltages below 85% to 90% of the nominal value could cause some induction motors to stall and draw high reactive current. For the P-V analysis, the Foothills Area is defined as the "sink" subsystem for the P-V analysis. Surrounding zones became the "source" subsystem for P-V analysis.

The following is the procedure that is followed in the studies as defined by the WECC Voltage Stability Criteria document:

1. Start with the base case to represent maximum rating and worst load conditions for the interface selected.
2. Identify the critical bus.
3. Assume constant MVA loads.
4. Increase interface flows in small steps.
5. Automatic system adjustments that would occur within three minutes are allowed for increasing the interface. These adjustments include those for tap changing transformers, phase shifting transformer adjustments, and automatic switched shunt capacitors.
6. Apply the critical contingency and solve the power flow case.
7. Record the voltage for the critical bus identified.
8. Repeat steps three through seven until the nose point of the curve had been reached or the case does not solve.
9. Plot the P-V curve and determine the real power margin.

P-V Analysis Solution Options:
Subsystem "Sink":
"Foothills" consisted of PSS/E

Subsystem "Source":
"SOURCE" consists of PSS/E power flow zones outside "Foothills"

The power transfer between the two subsystems is incremented in a defined step size for a series of ac power flow calculations while the bus voltages, generator outputs and the branch flows of the system are monitored. The following assumptions are made for the solutions:

Base Case Solution Options:
Lock Taps, disable area interchange control, lock switched shunts

Contingency Case Solution Options:
Lock Taps, disable area interchange control, lock switched shunts

Transfer dispatch methods:
For study “source” system – “DFAX generation”
For opposing “sink” system – “DFAX load”

Minimum monitored bus voltage: 0.90 p.u.

Phase I Transmission Report

for the

Colorado Coordinated Planning Group

80x30 Task Force

Transmission Planning

Public Service Company of Colorado

Final Report

February 24, 2021

Contents

I. Executive Summary

This report summarizes the studies completed under the scope of work for the Colorado Coordinated Planning Group's (CCPG) 80x30 Task Force (80x30TF) for Phase I. Phase I evaluated transmission solutions that may accommodate generation resources necessary to meet 2030 carbon reduction goals of Public Service Company of Colorado (PSCo) and other Colorado utilities as set forth in Senate Bill 19-236 (SB19-236), focusing on geographic diversity of resources while maintaining system reliability. Specifically, the transmission system reliability analyses performed evaluated various high voltage transmission projects to integrate possible future generation related to Public Service Company of Colorado's (PSCo) 2021 Electric Resource Plan (ERP) through the combined efforts of the CCPG 80x30TF.

The purpose of the report is to summarize:

1. Reliability evaluation of new and renewed purchase power generation in the Energy Resource Zones (ERZs) 1, 2, 3, and 5 in Northeastern, Eastern, and Southern areas of Colorado;
2. Proposed geographically diverse transmission projects to accommodate new renewable energy resources; and
3. Injection capability analysis at various locations on the Colorado transmission system.

The results of the study indicate that a new wide-area 345 kV transmission project interconnecting at many locations in the Northeastern, Eastern, Southern, and Metro areas of the transmission system can accommodate potential generation necessary to facilitate PSCo and potentially other utilities' 2030 carbon reduction goals. Energy storage as a non-wires alternative alone was deemed inadequate to deliver the resources from the remote energy resource zones to centralized load centers of the Front Range.

The transmission identified by the study would significantly improve the reliability of the Colorado transmission network by providing (1) additional high voltage transmission through the eastern portion of Colorado, and (2) greater access to and support of the existing transmission currently serving the Denver Metro area. The proposed transmission interconnections and terminations studied were selected based on their proximity to areas with high potential for low emission renewable energy resources. The general project areas include at least 13 Colorado counties (Weld, Morgan, Washington, Kit Carson, Cheyenne, Kiowa, Prowers, Bent, Otero, Pueblo, El Paso, Elbert, and Arapahoe). The preferred transmission Alternative is shown in Figure 1 with new 345 kV double circuit lines shown in blue overlaid on the Colorado SB07-100 Energy Resource Zone Map.

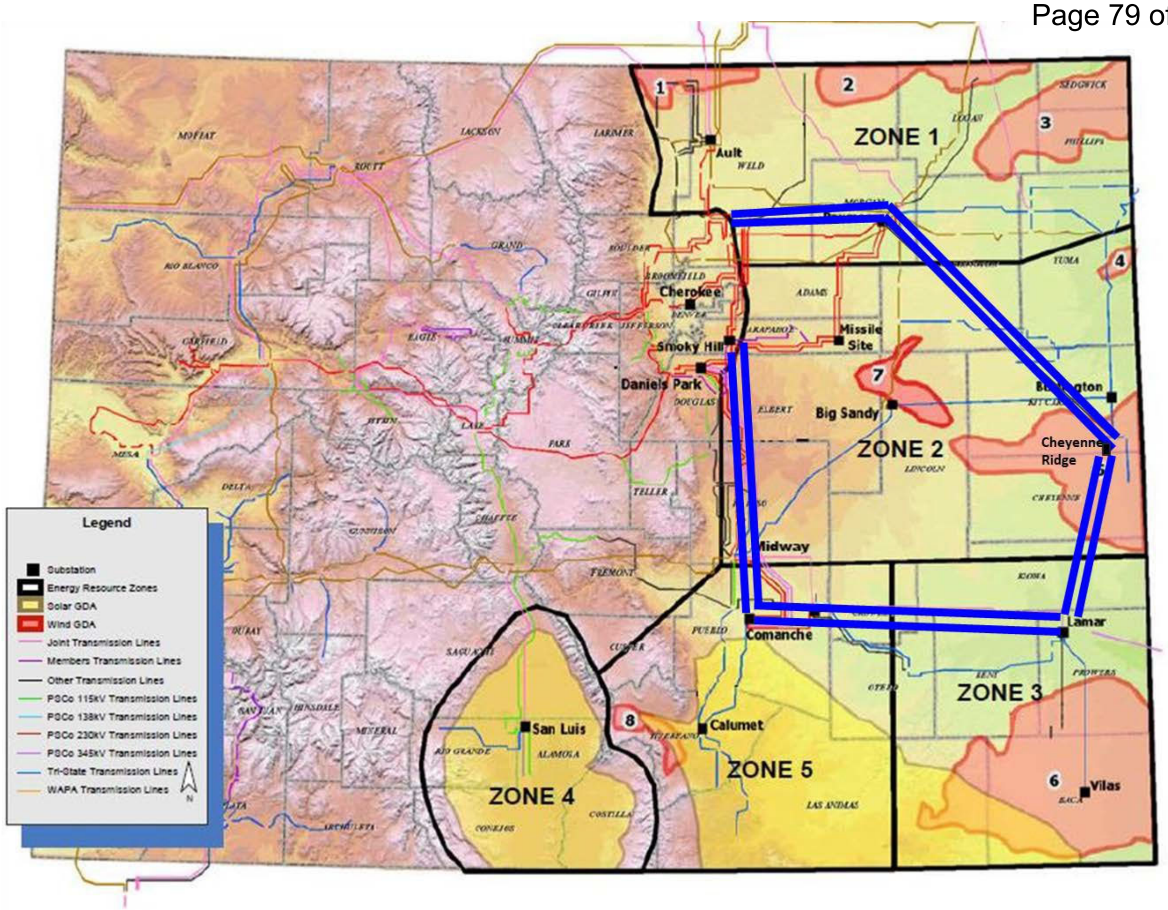

Figure 1: Proposed 345 kV Transmission Project

II. Background

On December 4, 2018 Xcel Energy announced a 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 (80x30). On May 30, 2019, as part of a historic climate legislation package, the Colorado Governor signed into law SB19-236. SB19-236 requires select utilities to meet these same carbon reduction goals and establishes a regulatory framework for doing so. SB19-236 also requires Public Service Company of Colorado (PSCo) an Xcel Energy, Inc. company, to include in its next Electric Resource Plan (ERP), a Clean Energy Plan that sets forth a plan of actions and investments, including generation and transmission plans that meet the requirements of SB19-236. PSCo plans to file an ERP and Clean Energy Plan in early 2021 describing its generation and transmission plans for meeting the 2030 carbon emissions reduction goal set forth in SB19-236. Under Colorado Public Utilities Commission (Commission) rules, investor owned utilities (PSCo and Black Hills), and wholesale electric cooperatives (Tri-State Generation & Transmission Association "Tri-State") are required to file an electric resource plan at least every four years to provide the Commission with an evaluation of future customer energy needs and a plan for how best to meet those needs. PSCo will include a Clean Energy Plan with its resource plan filing in 2021. In January 2020, Tri-State announced its Responsible Energy Plan, which includes a goal of 50% of the energy consumed by its members coming from renewable resources by 2024. Further, Tri-State's preferred plan[1] in its December 2020 ERP filing is 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. Other, non-Commission regulated Colorado utilities have also indicated support for looking at plans to reach Colorado's carbon reduction goals.

Traditionally, the transmission system in Colorado has been designed and constructed based on known generation additions to each provider's system. However, waiting to design and construct transmission in the wake of generation acquisition has resulted in numerous limitations to selecting and interconnecting new generation, especially beneficial energy resources located in renewable energy rich areas such as Northeastern, Eastern, and Southern Colorado, thus resulting in a "chicken and egg" timing dilemma. The time needed to develop and construct renewable resources, such as wind and solar, is much less than traditional fossil fuel plants, which in the past allowed time for transmission to be constructed to interconnect and deliver the generation. Waiting until generation projects are identified to plan transmission is no longer suitable, especially under Colorado's policy goal of reducing carbon dioxide emissions from Colorado's electric sector. SB19-236 recognizes that transmission is a critical element to achieving the state's clean energy targets as it will provide access to renewable energy rich areas in Colorado as well as other beneficial energy resources.

SB19-236 recognizes the need to address this dilemma. To aid in resolving these issues, the CCPG launched the 80x30TF in August 2020 to provide a forum for all stakeholders to collaboratively identify transmission infrastructure that will enable Colorado utilities to meet the state's decarbonization goals. The 80x30TF identified transmission that enables generation delivery from renewable energy rich areas that lack significant transmission access including northern, eastern and southern Colorado. As noted in the 80x30TF scope, this work is envisioned to be performed in two stages. This report provides the results and conclusions for Phase 1, which focuses primarily on PSCo

[1] Tri-State's preferred plan identifies the need for 400MW of new renewable generation in Eastern Colorado. The existing eastern Colorado transmission system cannot accommodate the identified new renewable generation.

and Tri-State's resource need and carbon reduction goals, focusing on ERZs 1,2,3 and 5. Phase II studies will include 80x30TF members' alternatives, additional studies requested by stakeholders.

Colorado transmission providers are able to use the 80x30TF as a public forum to develop and coordinate their respective transmission requirements and study plans.

The CCPG is a joint, high-voltage transmission system planning forum.[2] Its purpose is to assure a high degree of reliability through cooperative planning, development, and operation of the high- voltage transmission system in the Rocky Mountain Region of the Western Electricity Coordinating Council (WECC). The CCPG provides a technical forum to complete reliability studies and accomplish coordinated planning under the single-system planning concept. The CCPG, among other things, (a) facilitates local utilities' compliance with FERC's Order No. 890 and State Commission Rules, criteria, policies and guidelines and (b) provides a forum for interaction with stakeholders. CCPG recognizes the FERC Order 1000 principles for transmission planning: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation. PSCo proposed the 80x30TF and subsequently received approval under CCPG on August 20, 2020 to organize the task force as a public venue to discuss studies and transmission projects seen necessary to integrate the 80% carbon reduction plan by 2030. Specifically, the 80x30TF is to serve as the transmission planning forum to develop the study process and identify the transmission alternatives that most effectively meet the needs of CCPG members and stakeholders. This forum allows stakeholders the opportunity to provide input, express needs, or identify concerns with respect to the development of transmission plans. Since launching in August 2020, the 80x30TF has met seven times, with participation from a broad range of stakeholders from the utility, developer, environmental, public interest, government, and consumer interest communities.

III. Scope, Purpose and Objectives

The 80x30TF developed a formal scoping document,[3] which identifies the purpose of the study, the process for the study, the transmission study models and assumptions, methodology, cost estimates, and schedule. The scope was further delineated into a Phase I and Phase II study. The scope and purpose of the Phase I study is to identify and propose a transmission plan that will enable PSCo to propose generation portfolios that can achieve the 80x30 clean energy target of SB19-236. At a high level, the objectives of the 80x30TF study was to result in a transmission plan that could:

- Accommodate generation resources necessary to meet 2030 carbon reduction goals;
- Maintain geographic diversity of resources; and,
- Ensure system reliability / minimize system impacts.

The resulting transmission plan is intended to meet the following objectives, which the 80X30 TF will continue to discuss and evaluate:

[2] The CCPG, the Southwest Transmission Planning Group (SWAT), and the Sierra Subregional Planning Group (SSPG) perform the transmission planning functions as Subregional Planning Groups (SPG) under WestConnect, which is a FERC Order No. 1000 planning region. The CCPG is one of at least five SPG's recognized by WECC.
[3] See the full Study Scope document at https://doc.westconnect.com/Documents.aspx?NID=19226

- Facilitate transmission access to new clean energy resources in Eastern Colorado located in or near designated Energy Resource Zones[4] (ERZs) 2 & 3 identified as per SB07-100. (Figure 2 shows a map of the Colorado ERZs).
- Enable delivery of electric power output from new clean energy resources located in or near designated ERZs 1, 2, 3 & 5 to the load centers along the Front Range.
- Provide new interconnection points to facilitate development of new clean energy resources located in or near ERZs 1, 2, 3 & 5.
- Achieve adequate reliability and operational flexibility of the resulting interconnected transmission system in Colorado for enabling significantly increased penetration of new clean energy resources.

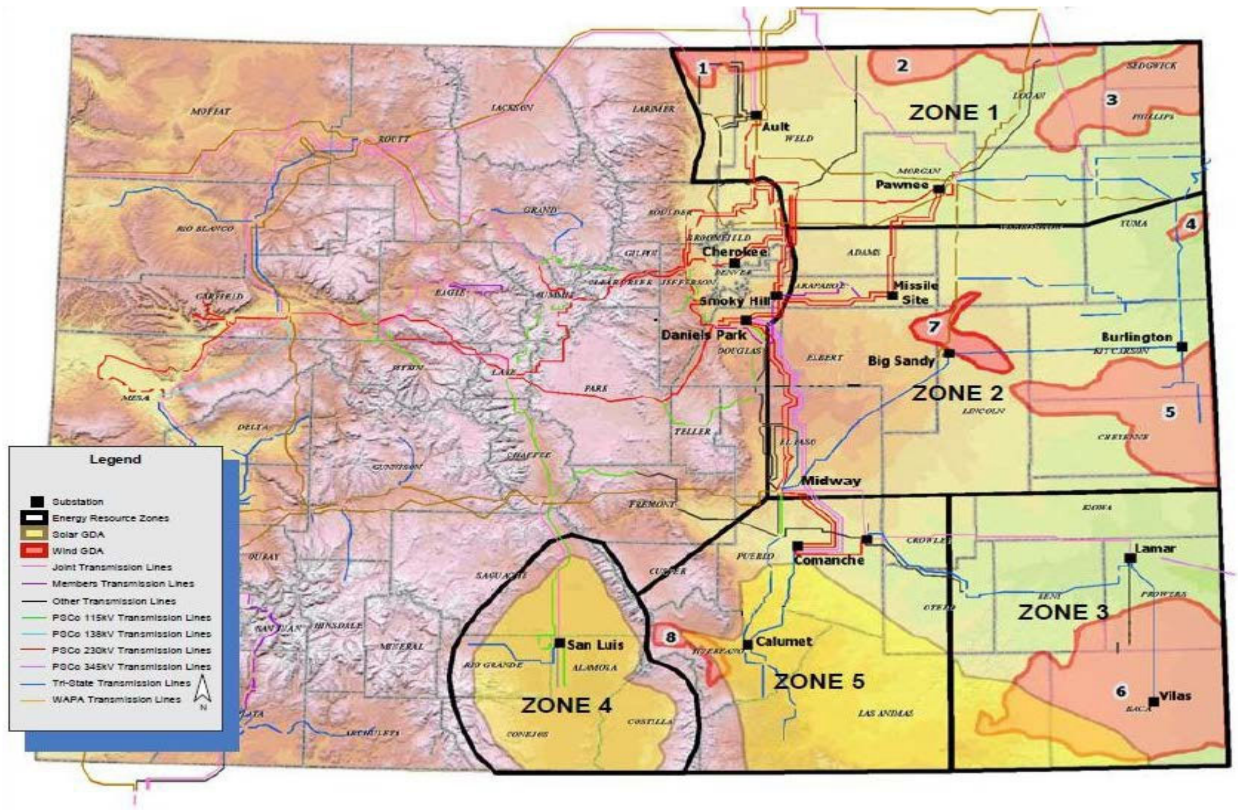

Figure 2: SB07-100 Energy Resource Zones

IV. Stakeholder Process

The CCPG is principally a subregional transmission planning group whose interest is ensuring the reliability of the interconnected transmission system in the CCPG footprint. Over the years, and as more non-utility generation owners and developers have taken greater interest in the planning and availability of the transmission system in Colorado, CCPG has offered increased opportunities for stakeholder participation and input to transmission planning considerations. Consistent with this principle, this study utilized the 80x30TF of CCPG as a forum to inform interested stakeholders of

[4] Energy Resource Zones are defined in C.R.S. 40-2-126 and have been presented to the Commission in PSCo's SB07-100 Reports.

the studies and to gather comments and alternatives for evaluation. The purpose of the group is to assure a high degree of reliability in the planning, development, and operation of the high voltage transmission system in the Rocky Mountain Region.

In the first 80x30TF meeting in October 2020, PSCo identified the need to develop transmission plans that would enable PSCo to achieve its 80x30 clean energy targets by maintaining geographic diversity of resources. A path to maintaining geographic diversity is facilitating transmission access to new renewable energy resources in ERZs 1, 2, 3 and 5. Through the open coordination process, other Colorado utilities identified solutions that would help meet their public policy needs too. Several meetings were held that included participation from a wide variety of stakeholders, including[5]:

- Apex Clean Energy
- Black Hills Energy
- Colorado Springs Utilities
- Dietze and Davis, on behalf of Independent Power Producers
- Enel North America
- Energy Strategies
- Grid Strategies
- Interwest Energy Alliance
- Juwi Inc
- National Grid Renewables
- Office of Consumer Council
- Onshore Wind
- Platte River Power Authority
- Public Service Company of Colorado
- Savion LLC
- Staff of the Colorado Public Utilities Commission
- Szot Energy Services
- Tri-State Generation & Transmission Association
- Western Resource Advocates

Meeting agendas, presentations, and meeting notes (including comments from stakeholders) are posted on the CCPG website.[6] The 80x30TF solicited and received comments to the 80x30TF Report, which are incorporated into this report. Additional stakeholder comments can be found in Appendix C.

V. Methodology

A. Studies

CCPG's 80x30TF study consisted of steady state (power flow) analysis. Facility loadings and voltages were monitored within the study area consistent with (NERC) and (WECC) standards. The Task Force used the WECC approved base cases as the basis for the power flow analysis as

[5] Additional stakeholders participated in the final meeting(s) including, RES and Invenergy.
[6] http://regplanning.westconnect.com/ccpg_80_30_tf.htm

described below. A benchmark analysis was performed to enable the comparison to alternative transmission plans. The benchmark case started from the WECC 2030 heavy summer case. The WECC 2030 heavy summer case was updated to reflect changes to the system since the time when those cases were approved as described below. Once the benchmark case was developed, steady state power flow and voltage comparison analyses were conducted for each transmission system alternative. From this analysis, the 80x30TF developed recommended transmission plans necessary to satisfy the objectives presented above and identified preferred alternatives.

B. Modeling

1. Cases

The technical analysis consisted of steady state (power flow) analysis using conventional transmission planning models. Studies utilized a ten-year transmission system planning model that originated from the approved WECC 30HS1 model.

2. Transmission Modeling

All existing transmission planned for the study horizon, 2020-2030, are included in the benchmark study case. The models reflect transmission facilities that are presently in-service and transmission facilities that are expected to be in-service during the study horizon. The additional significant transmission projects modeled in the benchmark case are:

- Missile Site – Pronghorn – Shortgrass 345 kV Gen-Tie (in-service)
- Pawnee – Daniels Park 345 kV Transmission Project (in-service)
- PSCo Voltage Control Facilities for the Colorado Energy Plan (in-service)
- Waterton – Martin 115 kV line uprate (2021)
- Monument – Flying Horse 115 kV series reactor project (2023)
- Greenwood – Denver Terminal 230 kV Line (2022)
- CSU transformer project at Briargate (2023)
- Tundra 345 kV Switching Station[7] (2022)
- Wayne Child Phase II (2022)

3. Generation Modeling

All existing generation and resources planned for the study horizon, 2020-2030, are included in the benchmark study case. Appendix A identifies the generation modeled in the benchmark case.

The planned generation in the benchmark study case includes:

- Cheyenne Ridge 500 MW wind (in-service)
- Bronco Plains 300 MW wind (in-service)

[7] A switching station is a type of substation that operates at a single voltage level (and, therefore, does not have transformers that "transform" voltage from one voltage level to another).

- Mountain Breeze 169 MW wind (in-service)
- Niyol 200 MW wind (2021)
- Thunderwolf 200/100 MW solar/storage (2022)
- Neptune 250/125 MW solar/storage (2022)
- Hartsel 72 MW solar (2022)
- Colorado Energy Plan generator at Boone/Midway 200 MW solar (2022)
- Spanish Peaks I 100 MW solar (2023)
- Spanish Peaks II 40 MW solar (2023)

New generation was added to the models on top of the existing or planned generation provided above. For the purposes of this analysis, "new generation" is a general term use to reflect generation not existing in the benchmark case. Additional transmission needed to meet 80x30 carbon reduction goals was determined by dispatching 3000 MW of new renewable generation and 3000 MW of existing renewable generation in ERZs 1, 2, 3, and 5, resulting in over three quarters of the PSCo Balancing Area (BA) demand served from renewable sources in the ERZs. New generation was located in different zones to maintain the study objective of geographical diversity of resources. The study cases for benchmark and Alternative 1 assumed 1500 MW dispatch of new renewable generation located in each the Northeast and South geographic areas. The study cases for alternatives 2-7 moved 1000 MW dispatch of new renewable generation from the South to the Southeast geographic area by including new transmission to the Southeast area. The interchange of the PSCo BA was not changed from the WECC 30HS1 model and therefore generation was not dispatched to areas outside of the PSCo BA. Table 1 below depicts the megawatts (MW) dispatched in each geographic area for every alternative studied.

Table 1: General Dispatch Assumptions

Geographic Area	ERZ	Benchmark & Alt 1 (MW)	Alts 2-7 (MW)
Northeast (new)	1,2	1500	1500
Northeast (existing)	1,2	1500	1500
South (new)	5	1500	500
South (existing)	5	1500	1500
Southeast (new)	3	0	1000
Interchange	N/A	795	795
Cabin Creek (existing)	N/A	150	150
Cherokee (existing)	N/A	350	350
Rest of PSCo (existing)	N/A	Load balance need	Load balance need

The description of the alternatives is discussed below in the 80x30 Carbon Reduction Goal Study Results section.

VI. Criteria

The study adhered to all applicable NERC Reliability Standards and WECC Regional Criteria. The pertinent System Performance Criteria for this study are included below in Sections A and B.

A. Steady State Voltage Limit Criteria[8]

Voltage violations requiring corrective actions are identified in steady state simulations when steady state voltages at extra high voltage Bulk Electric System (BES) buses are outside the following acceptable voltage limits:

- Normal (no contingency) conditions: Vmin = 0.95 per unit, Vmax = 1.05 pu
- Post-contingency conditions: Vmin = 0.90 pu, Vmax = 1.10 pu
- Voltages flagged if outside 0.90 – 1.10 per unit, and/or if the change in voltage exceeded 0.08 per unit

The screening criterion for generator voltage ride-through[9] capability is 0.90 pu to 1.10 pu for all planning event (P1 to P7[10]) contingencies. If the initial screening simulation indicates that the generator bus voltage is outside this range, follow-up simulations are performed as necessary based on a review of the generator's actual voltage ride-through capability.

B. Facility Loading Criteria

a) System-intact and Prior-Outage Conditions:
- Line loading monitored for 100% of the established lowest-rated equipment rating, as well as the conductor rating.
- Transformer loading monitored to 100% of the highest name plate rating or owner-provided rating.

b) Contingency (Forced-Outage) Conditions
- Line loading monitored for 100% of the established lowest-rated equipment rating, as well as the conductor rating.
- Voltages flagged if outside 0.90 – 1.10 per unit, and/or if the change in voltage exceeded 0.08 per unit.

VII. Cost Estimates

Cost estimates for each alternative were derived from employing the unit cost estimates from Midcontinent Independent System Operator (MISO) MTEP20 Transmission Cost Estimation Guide.[11] 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.

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[8] These criteria are the same as those specified in WR1, parts 1.1.1 and 1.1.2 in the WECC Regional Criterion TPL-001-WECC-CRT-3.
[9] Ride-through is an industry term to describe generation that can withstand system disturbances that cause voltage fluctuations.
[10] P7 contingency is defined in NERC TPL-001-4 Standard as a multiple contingency resulting in the loss of two adjacent (vertically or horizontally) circuits on common structure or loss of a bipolar DC line.
[11] MISO's MTEP20 Transmission Cost Estimation Guide can be found at: https://cdn.misoenergy.org/20200414%20PSC%20Item%2007%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP%202020_DRAFT_April_clean441565.pdf

Transmission line lengths are approximations with actual line routing unknown at this time. Unit costs used from the MISO MTEP20 guide include:

- $2.6 million per mile for single circuit 345 kV line
- $4.5 million per mile for double circuit 345 kV line

The cost estimates were used for alternative comparison purposes only in determining the preferred alternatives. 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. PSCo will refine and present more detailed cost estimates in forthcoming filings with the Commission.

VIII. Benchmark Case Analysis Results

A. Description

A benchmark analysis was performed to determine if there were any potential reliability issues associated with the proposed 80x30 carbon reduction plan with a "do nothing" transmission case. A high-level benchmark case one-line diagram of the transmission system in Northeastern, Eastern, and Southern Colorado is shown in Figure 3 below. The diagram ends at some of the interconnection points into the Denver Metro Area, including Waterton, Daniels Park, and Smoky Hill/Harvest Mile Substations. This figure's purpose is to provide a comparison of the transmission elements for the various alternatives. The benchmark cases include all CCPG member facilities included in the WECC-30HS1 model.

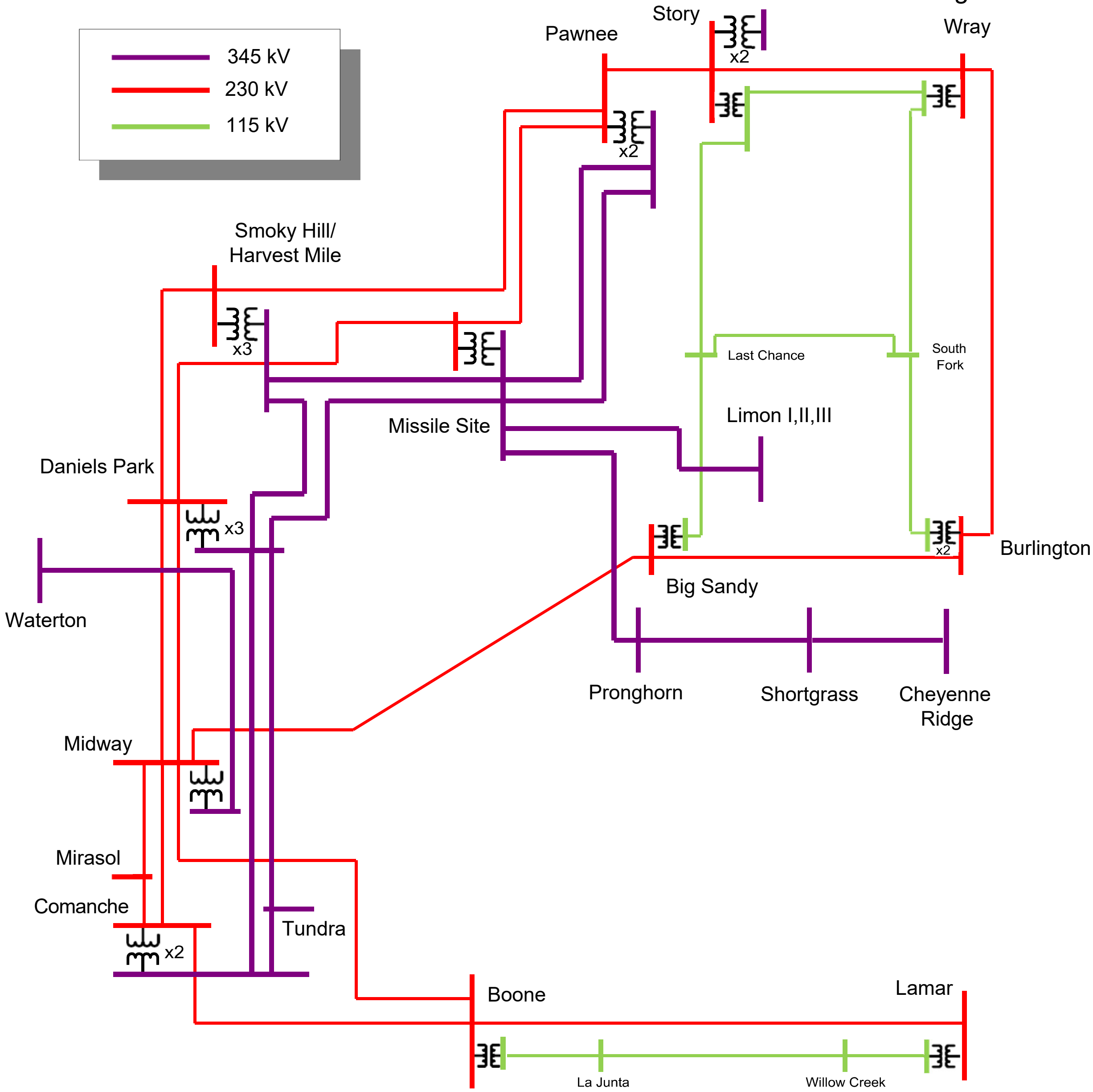

Figure 3: Benchmark System

B. Analysis Results

New generation for the Benchmark case was placed at Pawnee and Tundra Substations, effectively within ERZs 1 and 5. New generation was not placed at other locations on the system because previous analysis has determined little to no injection capability at locations within ERZs 2 and 3. The analysis identified twenty-three system intact and contingency overloads in the benchmark case that were not seen when compared to all of the other alternatives studied.

C. Summary

The studies show the existing transmission system, which is considered a "do-nothing" transmission case, is unable to reliably accommodate new generation in ERZs 1, 2, 3, and 5, and likely unable to accommodate 2030 carbon reduction goals. Previous studies have shown no additional generation is able to be accommodated at Cheyenne Ridge and Lamar Substations.

IX. 80x30 Carbon Reduction Goal Analysis Results

As stated above, the current transmission system is limited in its ability to reliably add and deliver new generation in ERZs 2, 3 and 5 necessary to meet the 80x30 carbon reduction goals with geographical diversity. Therefore, it was necessary to develop additional transmission elements that could be included in the modeling to see how various system modifications and additions could start to accommodate generation additions that meet the 80x30 criteria. The report steps through each alternative studied and provides the alternative description, study results, summary and cost. The following table is a snapshot of these alternatives. For purposes of the study, new 345 kV lines were assumed to be constructed as bundled Aluminum Conductor Steel Reinforced (ACSR) 1272 Bittern conductor with a summer normal rating of 1637 MVA (actual ratings will depend on final project design).

Table 2: Summary of Alternatives

New Transmission Facility	Alt 1	Alt 2	Alt 3	Alt 4	Alt 5	Alt 6	Alt 7
• 345 kV switching station near Cheyenne Ridge West	x	x	x	x	x	x	x
• 345 kV bus at Burlington Substation					x		
• 345 kV double circuit line between Cheyenne Ridge and Pawnee	x	x	x	x			
• 345 kV double circuit line between Cheyenne Ridge and Burlington					x		
• 345 kV double circuit line between Cheyenne Ridge and Story						x	x
• 345 kV double circuit line between Burlington and Story					x		x
• 345 kV double circuit line between Story and Pawnee					x	x	x
• 345 kV bus at Fort St Vrain Substation	x	x	x	x	x	x	x
• 345 kV double circuit line between Pawnee and Fort St Vrain	x	x	x	x	x	x	x
• 345 kV double circuit line between Tundra and Harvest Mile	x	x	x	x	x	x	x
• 345 kV switching station at Lamar		x	x	x	x	x	
• 345 kV substation at Lamar							x
• 345 kV double circuit line between Lamar and Tundra		x	x		x	x	x
• 345 kV single circuit line between Lamar and Tundra				x			
• 345 kV double circuit line between Cheyenne Ridge and Lamar			x		x	x	x
• 345 kV single circuit line between Cheyenne Ridge and Lamar				x			
New 345 kV double circuit tower lines (miles)	330	460	550	330	550	550	550
New 345 kV single circuit tower lines (miles)				220			
Estimated costs (based on MISO unit costs in millions)	$1,500	$2,000	$2,400	$2,000	$2,400	$2,400	$2,400
Access to ERZ	1,2,5	1,2,3,5	1,2,3,5	1,2,3,5	1,2,3,5	1,2,3,5	1,2,3,5

A. Alternative 1

1. Description

The configuration for Alternative 1 is shown in Figure 4 below. Alternative 1 would create a new Cheyenne Ridge to Pawnee to Fort St. Vrain double-circuit 345 kV line and a Tundra[12] to Harvest Mile double circuit 345 kV line, that assumed the following components:

- 345 kV switching station near Cheyenne Ridge West
- 345 kV double circuit line between Cheyenne Ridge and Pawnee
- 345 kV bus at Fort St Vrain Substation
- 345 kV double circuit line between Pawnee and Fort St Vrain
- 345 kV double circuit line between Tundra and Harvest Mile

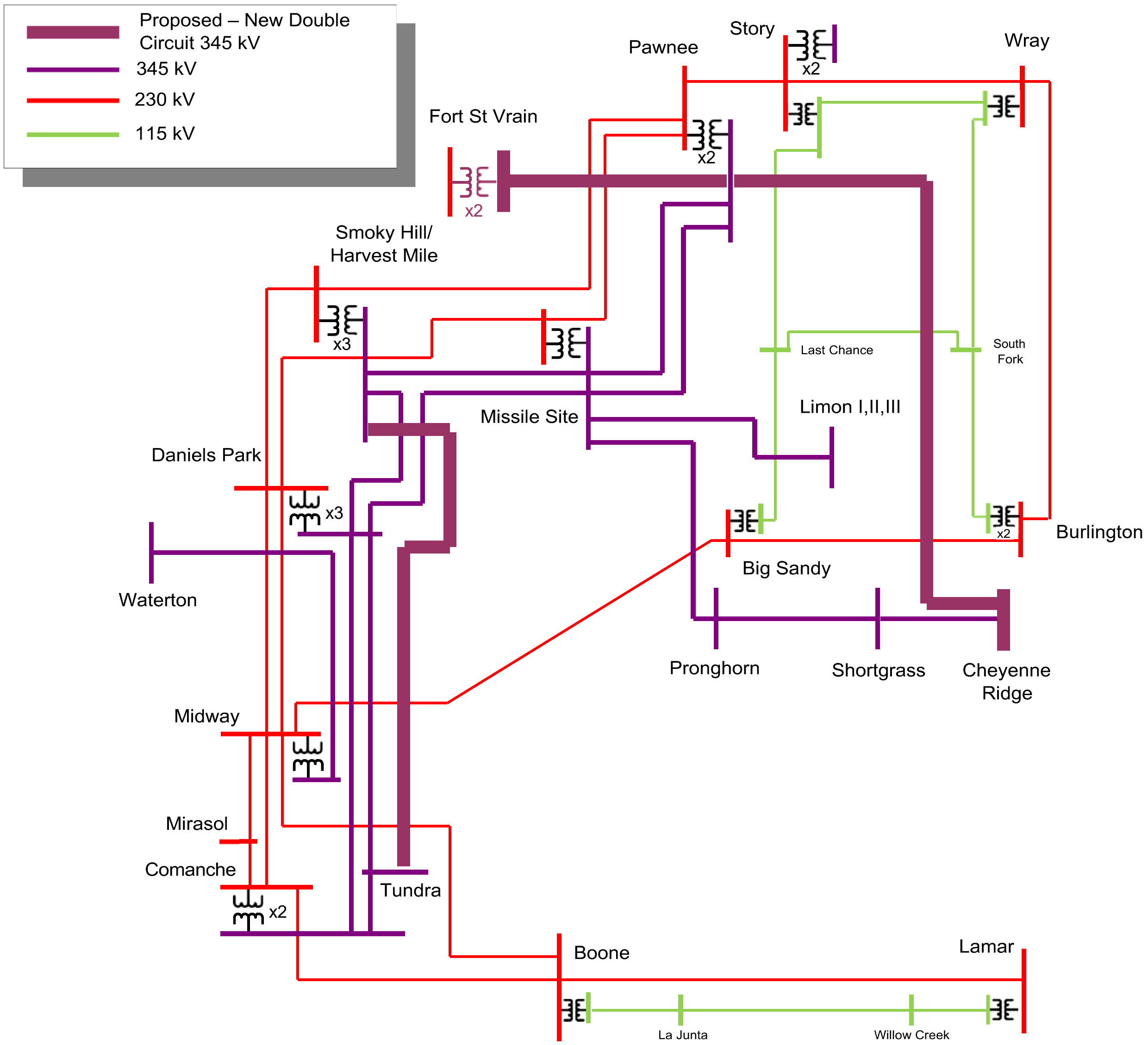

Figure 4: Alternative 1

[12] Tundra Substation Switching Station is a new, yet to be constructed interconnection facility planned to interconnect a solar generation resource approved as part of PSCo's Colorado Energy Plan Portfolio in PSCo's 2016 Electric Resource Plan.

2. Analysis Results

For Alternative 1, new generation was placed at Comanche, Pawnee, Missile Site, and Cheyenne Ridge Substations, effectively within ERZs 1, 2, and 5. The new generation was dispatched to 1500 MW both in the Northeast and South areas for a total of 3000 MW.

Alternative 1 would consist of approximately 330 miles of new 345 kV double circuit tower lines. The planning level estimate using MISO unit costs totals approximately $1.5 billion.

3. Summary

While Alternative 1 provides new generation at Comanche, Pawnee, and Cheyenne Ridge Substations, the alternative (1) does not provide new service into ERZ 3 near the Lamar area, and (2) is not looped to other locations on the system. While Alternative 1 achieves limited reliability benefits, other alternatives produce greater reliability benefits. Additionally, Alternative 1 also does not accommodate the desired geographical diversity to achieve public policy goals of carbon reduction by not providing transmission access to ERZ 3. Also, the study showed concerns with NERC P7 (common tower, N-2) outages of the new lines. For the P7 outage of the Cheyenne Ridge – Pawnee 345 kV Lines a Remedial Action Scheme (RAS) would likely be required to drop significant amounts of generation to insure stability of the system and thermal loading within ratings of the Missile Site – Pronghorn – Shortgrass – Cheyenne Ridge 345 kV Gen-Tie. Therefore, Alternative 1 does not appear to be a reasonable alternative to interconnect new generation in all the ERZs as defined in the geographical diversity objectives of the study.

B. Alternative 2

1. Description

The configuration for Alternative 2 is shown in Figure 5. The alternative creates a new Cheyenne Ridge to Pawnee to Fort St. Vrain double circuit 345 kV line and a Lamar Area to Tundra to Harvest Mile double circuit 345 kV line, and assumes the following components:

- 345 kV switching station near Cheyenne Ridge West
- 345 kV double circuit line between Cheyenne Ridge and Pawnee
- 345 kV bus at Fort St Vrain Substation
- 345 kV double circuit line between Pawnee and Fort St Vrain
- 345 kV double circuit line between Tundra and Harvest Mile
- 345 kV switching station at Lamar
- 345 kV double circuit line between Lamar and Tundra

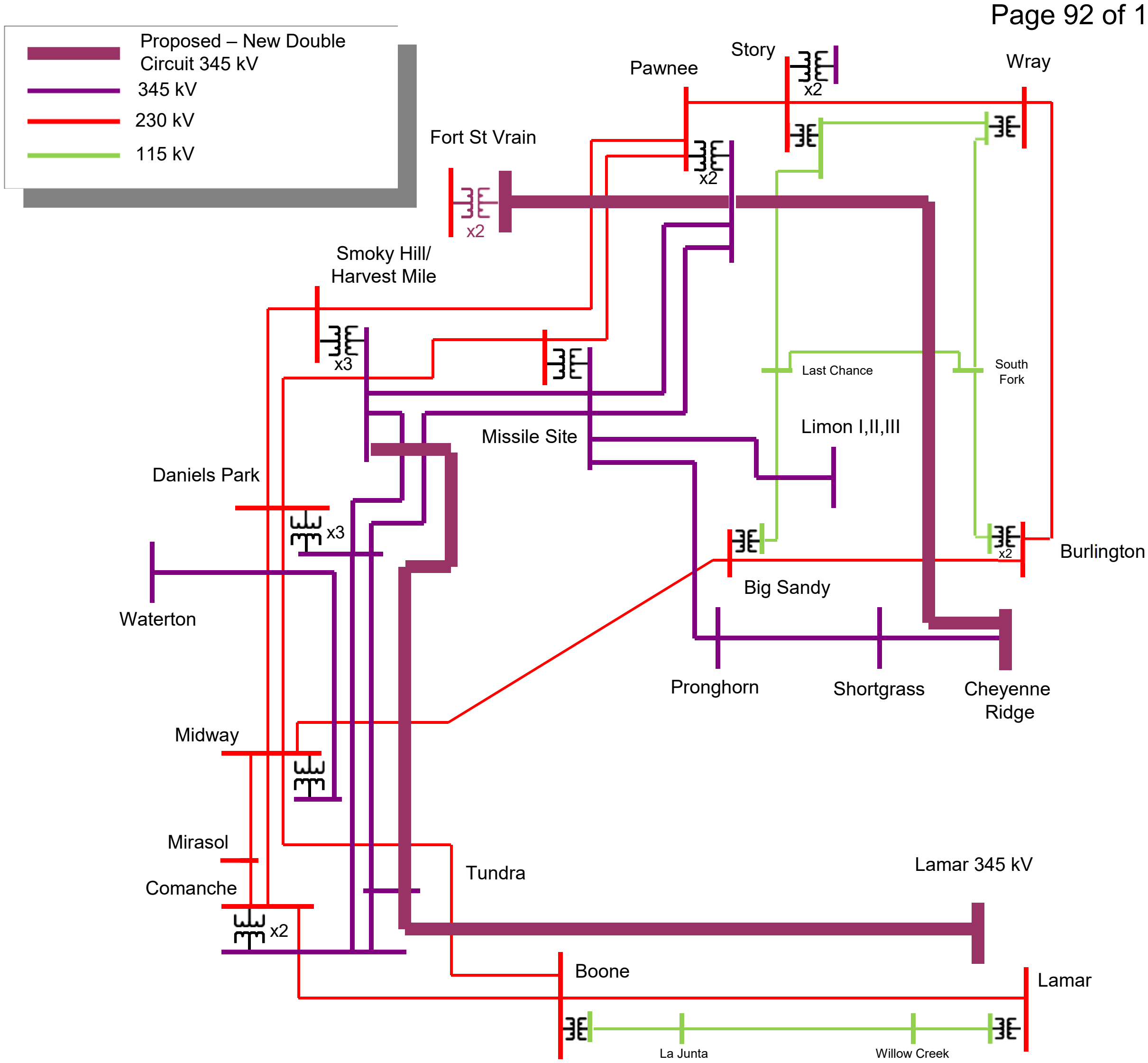

Figure 5: Alternative 2

2. Analysis Results

For Alternative 2, new generation was placed at Comanche, Lamar, Pawnee, Missile Site, and Cheyenne Ridge Substations, effectively within ERZs 1, 2, 3, and 5. The new generation was dispatched to 1500 MW in the Northeast, 500 MW in the South, and 1000 MW in the Southeast for a total of 3000 MW.

Alternative 2 would consist of approximately 460 miles of new 345 kV double circuit tower lines. The planning level estimate using MISO unit costs totals approximately $2.0 billion.

3. Summary

Alternative 2 effectively provides new generation capacity to meet 80x30TF objectives within all ERZs contemplated by the objective of the study. While the new double circuit 345 kV tower lines provide high ratings and reduced impedance paths, the study showed concerns with NERC P7 (common tower, N-2) outages of the new lines. For the P7 outage of the Cheyenne Ridge – Pawnee 345 kV Lines a Remedial Action Scheme (RAS) would likely be required to drop significant amounts of generation to insure stability of the system and thermal loading within ratings of the Missile Site – Pronghorn – Shortgrass – Cheyenne Ridge 345 kV Gen-Tie. For the P7 outage of Lamar – Tundra 345 kV Lines a significant amount of generation would be dropped from the system depending on how much generation is eventually installed at the Lamar 345 kV Station.

C. Alternative 3

1. Description

The configuration for Alternative 3 is shown in Figure 6. The alternative would create a new Cheyenne Ridge to Pawnee to Fort St. Vrain double circuit 345 kV line, Lamar Area to Tundra to Harvest Mile double circuit 345 kV line, and a Cheyenne Ridge to Lamar Area double circuit 345 kV line. Note the alternative does not interconnect to the existing Lamar 230 kV substation, and assumes the following components:

- 345 kV switching station near Cheyenne Ridge West
- 345 kV double circuit line between Cheyenne Ridge and Pawnee
- 345 kV bus at Fort St. Vrain Substation
- 345 kV double circuit line between Pawnee and Fort St Vrain
- 345 kV double circuit line between Tundra and Harvest Mile
- 345 kV switching station at Lamar
- 345 kV double circuit line between Lamar and Tundra
- 345 kV double circuit line between Cheyenne Ridge and Lamar

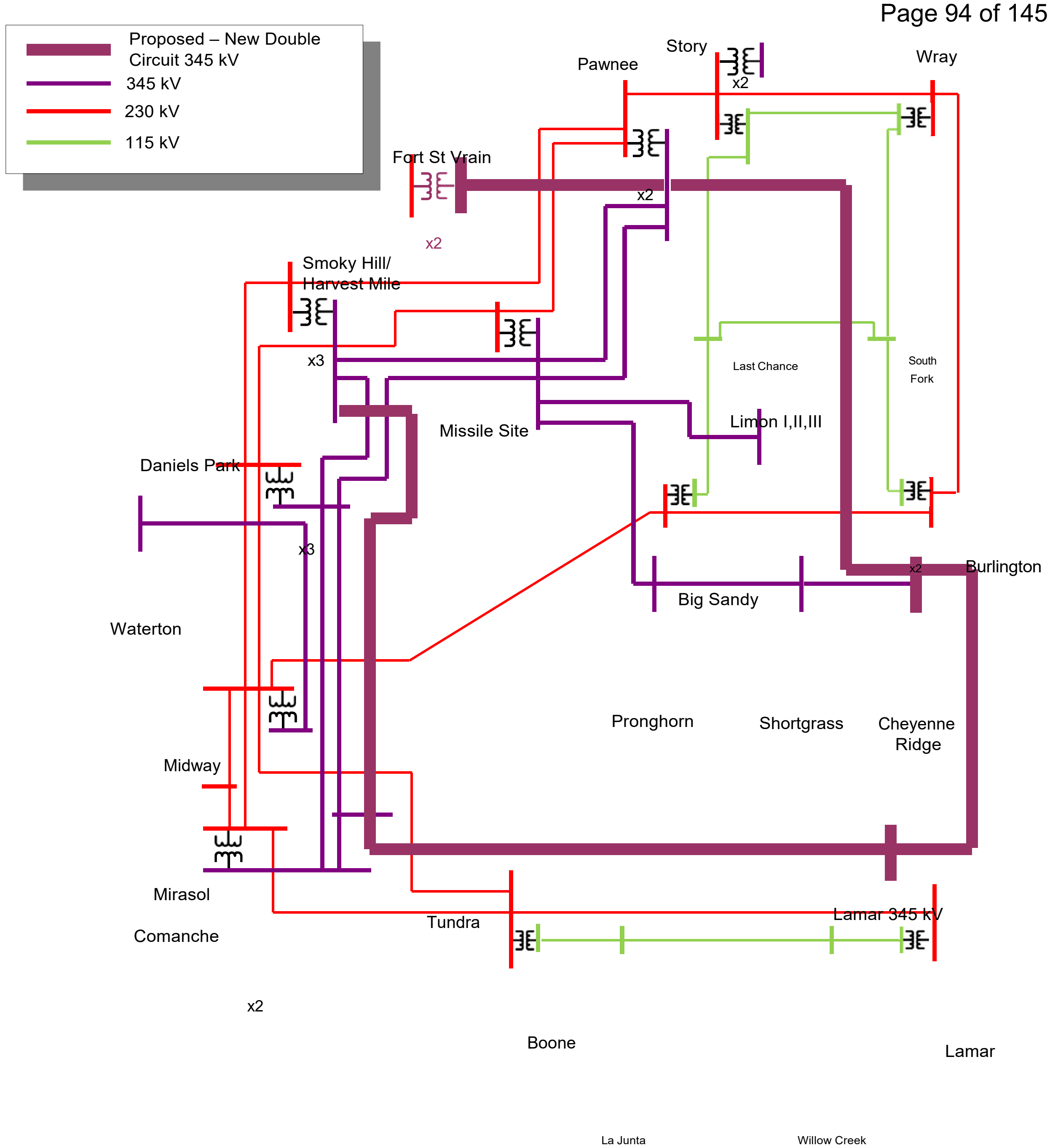

Figure 6: Alternative 3

2. Analysis Results

For Alternative 3, new generation was placed at Comanche, Lamar, Pawnee, Missile Site, and Cheyenne Ridge Substations, effectively within ERZs 1, 2, 3, and 5. The new generation was dispatched to 1500 MW in the Northeast, 500 MW in the South, and 1000 MW in the Southeast for a total of 3000 MW.

Alternative 3 consists of approximately 550 miles of new 345 kV double circuit tower lines. The planning level estimate using MISO unit costs totals approximately $2.4 billion.

3. Summary

Alternative 3 effectively provides transmission capacity for adding new generation toward meeting 80x30TF goals within all ERZs contemplated by the objective of the study. The study showed concerns with NERC P7 (N-2) outages similar to Alternative 2. However, the P7 issues were significantly reduced with the addition of the Cheyenne Ridge – Lamar double circuit 345 kV lines.

A Remedial Action Scheme (RAS) would likely be required but with less generation curtailment than Alternative 2.

D. Alternative 4

1. Description

The configuration for Alternative 4 is shown in Figure 7. The alternative creates a new Cheyenne Ridge to Pawnee to Fort St. Vrain double circuit 345 kV line, Lamar Area to Tundra single circuit 345 kV line, a Tundra to Harvest Mile double circuit 345 kV line, and a Cheyenne Ridge to Lamar Area single circuit 345 kV line. Note the alternative does not interconnect to the existing Lamar 230 kV substation, and assumed the following components:

- 345 kV switching station near Cheyenne Ridge West
- 345 kV double circuit line between Cheyenne Ridge and Pawnee
- 345 kV bus at Fort St Vrain Substation
- 345 kV double circuit line between Pawnee and Fort St Vrain
- 345 kV double circuit line between Tundra and Harvest Mile
- 345 kV switching station at Lamar
- 345 kV single circuit line between Lamar and Tundra
- 345 kV single circuit line between Cheyenne Ridge and Lamar

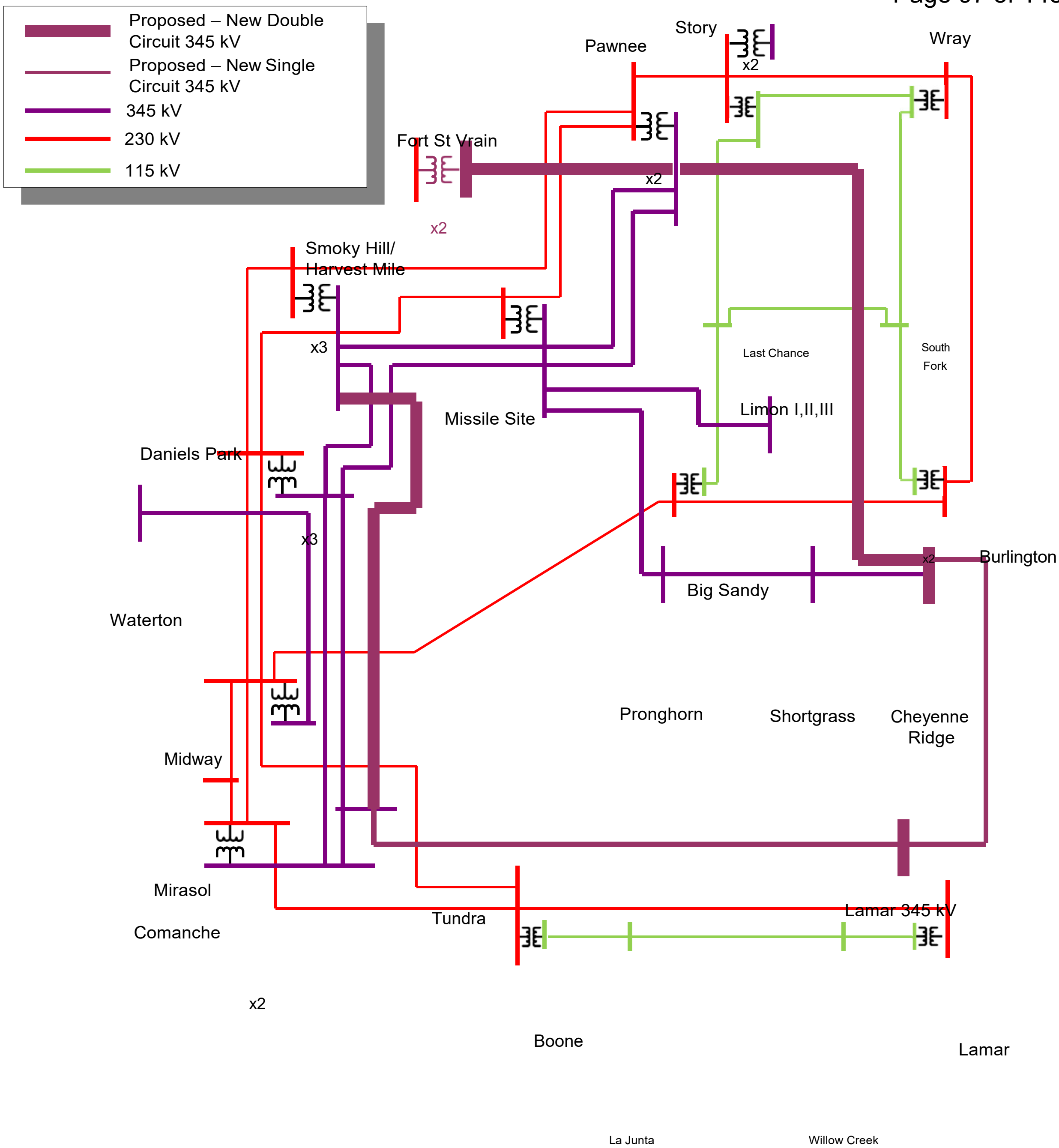

Figure 7: Alternative 4

2. Analysis Results

For Alternative 4, new generation was placed at Comanche, Lamar, Pawnee, Missile Site, and Cheyenne Ridge Substations, effectively within ERZs 1, 2, 3, and 5. The new generation was dispatched to 1500 MW in the Northeast, 500 MW in the South, and 1000 MW in the Southeast for a total of 3000 MW.

Alternative 4 would consist of approximately 330 miles of new 345 kV double circuit tower lines and 220 miles of new 345 kV single circuit lines. The planning level estimate using MISO unit costs totals approximately $2.0 billion.

3. Summary

Alternative 4 would effectively provide new generation capacity to meet 80x30TF objectives within all ERZs contemplated by the objective of the study. While the new single and double circuit 345 kV tower lines provide new lines in eastern Colorado, the study showed higher reactive support required at Lamar than Alt 3 to mitigate N-1 outages of the Lamar – Cheyenne Ridge or Lamar – Tundra 345 kV Lines. Also, the study showed concerns with NERC P7 (common tower, N-2) outages of the new lines. For the P7 outage of the Cheyenne Ridge – Pawnee 345 kV Lines a Remedial Action Scheme (RAS) would likely be required to drop significant amounts of generation to insure stability of the system and thermal loading within ratings of the Missile Site – Pronghorn – Shortgrass – Cheyenne Ridge 345 kV Gen-Tie and the Cheyenne Ridge – Lamar 345 kV line.

E. Alternative 5

1. Description

The configuration for Alternative 5 is shown in Figure 8. The alternative would create a new Cheyenne Ridge to Burlington to Story to Pawnee to Fort St. Vrain double circuit 345 kV line, Lamar Area to Tundra to Harvest Mile 345 kV double circuit line, and a Cheyenne Ridge to Lamar Area 345 kV double circuit line. Note the alternative does not interconnect to the existing Lamar 230 kV substation, and assumed the following components:

- 345 kV switching station near Cheyenne Ridge West
- 345 kV bus at Burlington Substation
- 345 kV double circuit line between Cheyenne Ridge and Burlington
- 345 kV double circuit line between Burlington and Story
- 345 kV double circuit line between Story and Pawnee
- 345 kV bus at Fort St Vrain Substation
- 345 kV double circuit line between Pawnee and Fort St Vrain
- 345 kV double circuit line between Tundra and Harvest Mile
- 345 kV switching station at Lamar
- 345 kV double circuit line between Lamar and Tundra
- 345 kV double circuit line between Cheyenne Ridge and Lamar

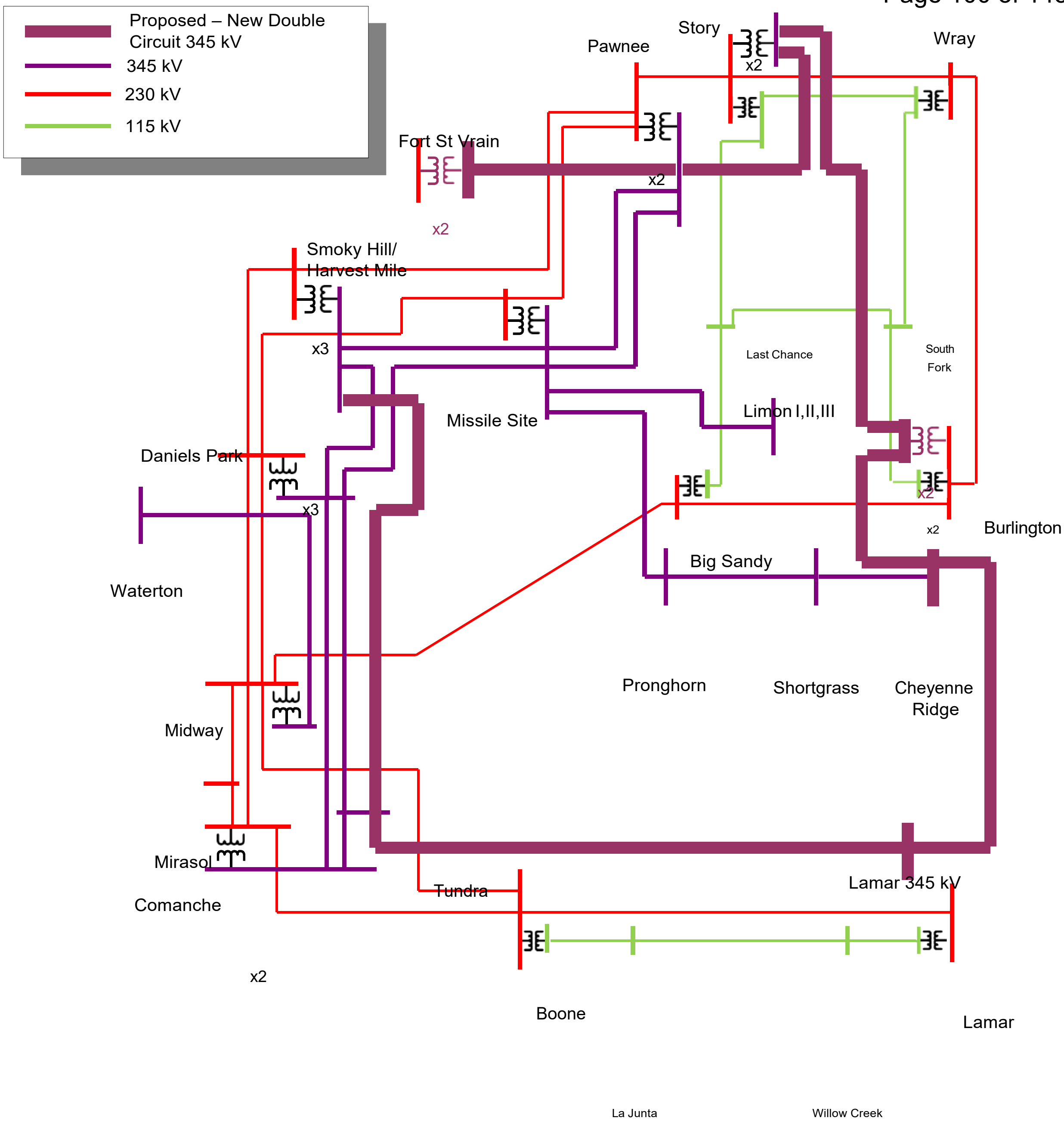

Figure 8: Alternative 5

2. Analysis Results

For Alternative 5, new generation was placed at Comanche, Lamar, Pawnee, Missile Site, and Cheyenne Ridge Substations, effectively within ERZs 1, 2, 3, and 5. The new generation was dispatched to 1500 MW in the Northeast, 500 MW in the South, and 1000 MW in the Southeast for a total of 3000 MW.

Alternative 5 would consist of approximately 550 miles of new 345 kV double circuit tower lines. The planning level estimate using MISO unit costs totals approximately $2.4 billion. While this approximate estimate is similar to Alternative 3, it is important to note the estimate methodology does not include substation work. Therefore, the cost would be higher than Alternative 3 with the addition of interconnections into Burlington (without an existing 345 kV yard) and Story Substations.

3. Summary

Alternative 5 would effectively provide capacity to meet 80x30TF objectives within all ERZs contemplated by the objective of the study and adds two interconnection points in eastern Colorado as compared to Alternative 3. The study showed no concerns with interconnection into Burlington and Story Substations.

F. Alternative 6

1. Description

The configuration for Alternative 6 is shown in Figure 8. The alternative creates a new Cheyenne Ridge to Story to Pawnee to Fort St Vrain double circuit 345 kV line, Lamar Area to Tundra to Harvest Mile 345 kV double circuit line, and a Cheyenne Ridge to Lamar Area 345 kV double circuit line. Note the alternative does not interconnect to the existing Lamar 230 kV substation, and assumed the following components:

- 345 kV switching station near Cheyenne Ridge West
- 345 kV double circuit line between Cheyenne Ridge and Story
- 345 kV double circuit line between Story and Pawnee
- 345 kV bus at Fort St Vrain Substation
- 345 kV double circuit line between Pawnee and Fort St Vrain
- 345 kV double circuit line between Tundra and Harvest Mile
- 345 kV switching station at Lamar
- 345 kV double circuit line between Lamar and Tundra
- 345 kV double circuit line between Cheyenne Ridge and Lamar

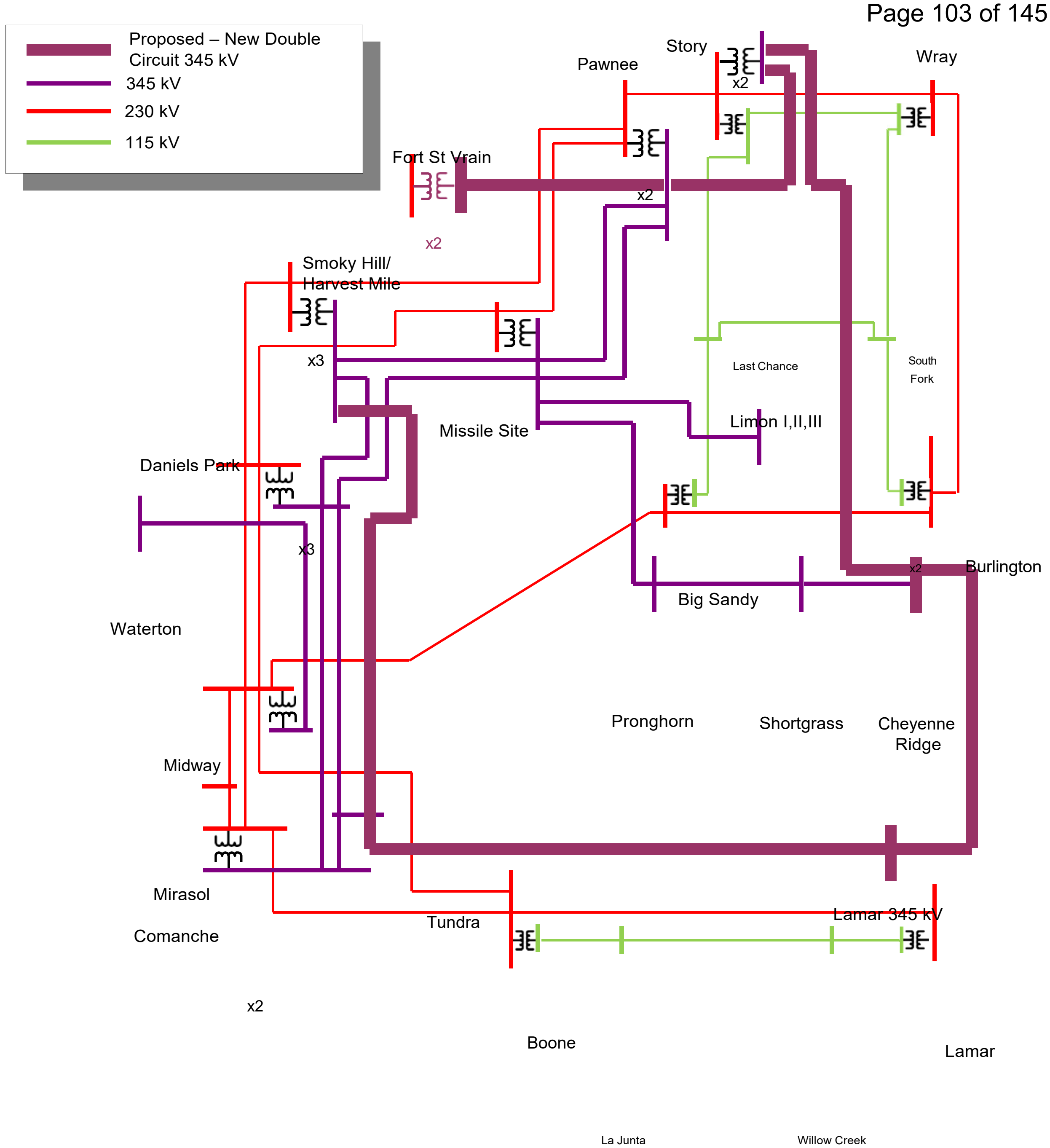

Figure 9: Alternative 6

2. Analysis Results

For Alternative 6, new generation was placed at Comanche, Lamar, Pawnee, Missile Site, and Cheyenne Ridge Substations, effectively within ERZs 1, 2, 3, and 5. The new generation was dispatched to 1500 MW in the Northeast, 500 MW in the South, and 1000 MW in the Southeast for a total of 3000 MW.

Alternative 6 would consist of approximately 550 miles of new 345 kV double circuit tower lines. The planning level estimate using MISO unit costs totals approximately $2.4 billion. While this approximate estimate is similar to Alternative 3 and Alternative 5, it is important to note the estimate methodology does not include substation work. Therefore, the cost would be higher than Alternative 3 and lower than Alternative 5 with the addition of the interconnection into Story Substation.

3. Summary

Alternative 6 would effectively provide capacity to meet 80x30TF objectives within all ERZs contemplated by the objective of the study and would add one additional interconnection point in eastern Colorado as compared to Alternative 3. The study showed no concerns with interconnection into Story Substation.

G. Alternative 7

4. Description

The configuration for Alternative 7 is shown in Figure 10. The alternative creates a new Cheyenne Ridge to Story to Pawnee to Fort St Vrain double circuit 345 kV line, Lamar to Tundra to Harvest Mile 345 kV double circuit line, and a Cheyenne Ridge to Lamar 345 kV double circuit line. This alternative builds upon Alternative 6 with an additional interconnection into the existing Lamar 230 kV substation, and assumed the following components:

- 345 kV switching station near Cheyenne Ridge West
- 345 kV double circuit line between Cheyenne Ridge and Story
- 345 kV double circuit line between Story and Pawnee
- 345 kV bus at Fort St Vrain Substation
- 345 kV double circuit line between Pawnee and Fort St Vrain
- 345 kV double circuit line between Tundra and Harvest Mile
- 345 kV bus at Lamar
- 345 kV double circuit line between Lamar and Tundra
- 345 kV double circuit line between Cheyenne Ridge and Lamar

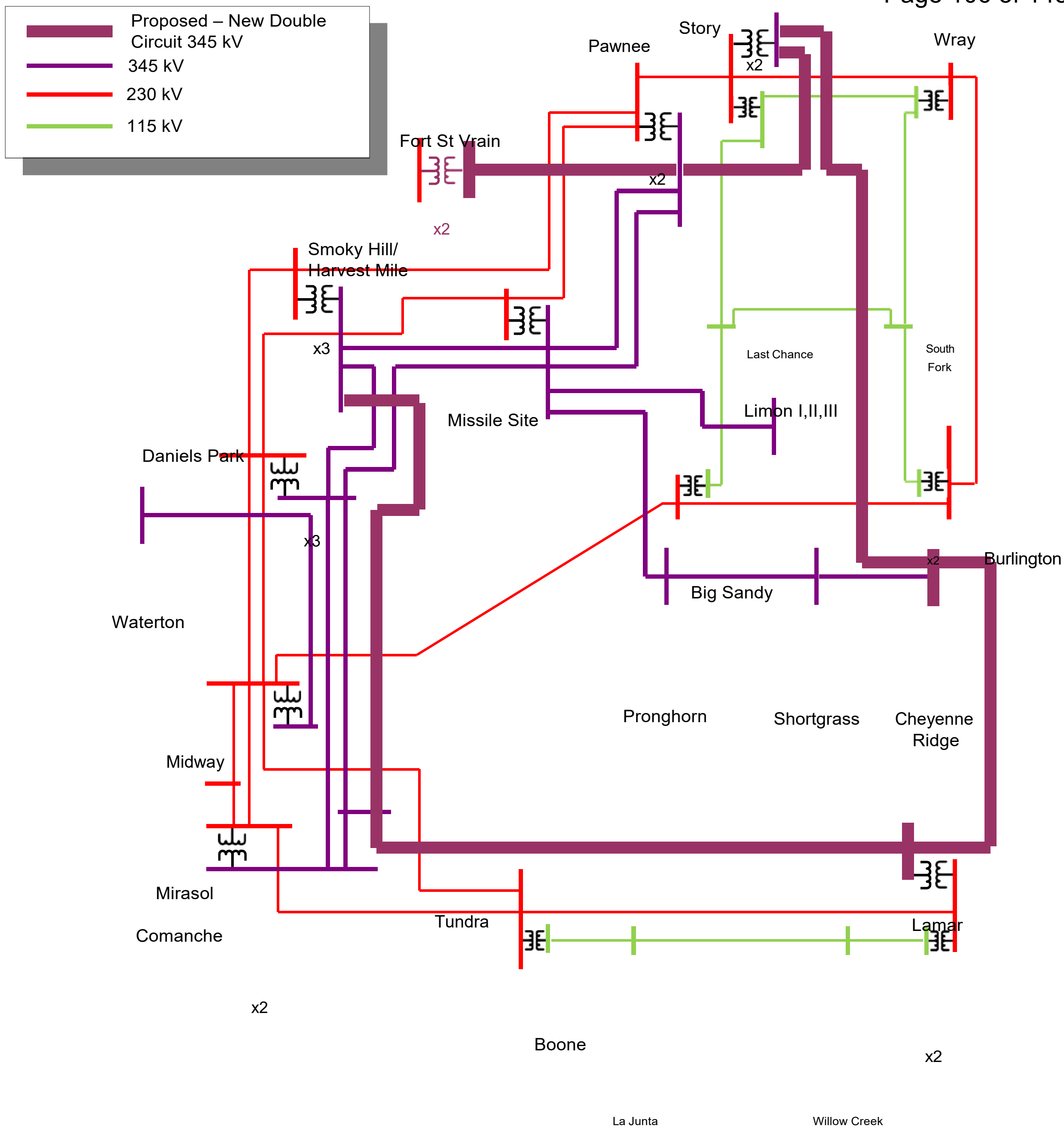

Figure 10: Alternative 7

5. Analysis Results

For Alternative 7, new generation was placed at Comanche, Lamar, Pawnee, Missile Site, and Cheyenne Ridge Substations, effectively within ERZs 1, 2, 3, and 5. The new generation was dispatched to 1500 MW in the Northeast, 500 MW in the South, and 1000 MW in the Southeast for a total of 3000 MW.

Alternative 7 would consist of approximately 550 miles of new 345 kV double circuit tower lines. The planning level estimate using MISO unit costs totals approximately $2.4 billion. While is approximate estimate is similar to Alternative 3 and Alternative 5, it is important to note the estimate methodology does not include substation work. Therefore, the cost would be higher than Alternative 3 and lower than Alternative 5 with the addition of the interconnection into Story and Lamar Substations.

6. Summary

Alternative 7 would effectively provide capacity to meet 80x30 goals within all ERZs contemplated by the objective of the study and would add two additional interconnection point in eastern Colorado as compared to Alternative 3. The study showed no concerns with interconnection into Story and Lamar Substations. Additionally, a new connection into the existing Lamar substation would effectively strengthen the Lamar area transmission system and mitigate existing reliability concerns of PSCo and Tri-State, specifically related to the outage of the Lamar-Boone 230kV line.

H. Alternatives Evaluation Study Results Summary

The number of overloaded facilities for the Benchmark and Alternative cases is shown in Table 3 below. As the table shows, there are significantly more overloaded facilities in the Benchmark case as compared to the Alternatives. Even with a reduced number of overloaded facilities, the Alternative cases continue to show overloaded facilities mostly in the Denver Metro Area. Mitigation of these overloaded facilities is outside the scope of the 80x30TF Phase I study and are planned to be addressed as more information is known on the specific location and technology type of future generation.

Table 3: Number of Overloaded Facilities

Region of Overloaded Facilities	80x30TF Bench	80x30TF Alt 1	80x30TF Alt 2	80x30TF Alt 3	80x30TF Alt 4	80x30TF Alt 5	80x30TF Alt 6	80x30TF Alt 7
Denver Metro	27	13	13	17	16	15	15	16
South	8	1	1	1	1	2	1	1
Southeast	4	2	2	2	2	2	2	1

A list of overloaded facilities can be found in Appendix B.

I. 345 kV versus 500 kV Transmission

The Task Force was presented with the concept of building a 500 kV double circuit loop using the same general paths as studied in the 345 kV study. This 500 kV discussion was raised toward the end of the Phase I Study activity, after the December meetings where the preferred 345 kV Alternatives were identified, thus it was not an alternative studied in Phase I. However, to the extent an alternative at 345 kV can meet the 80x30TF objectives for delivering electric power output from new clean energy resources located in or near the ERZs studied, 500 kV would also perform that function. However, more studies would be necessary to consider a cost to benefit analysis for introducing 500 kV in Colorado where currently no transmission at this voltage exists.

J. Energy Storage

The purpose of the 80x30TF is to develop a transmission expansion plan, which will enable Colorado utilities to achieve the 80 percent reduction in carbon emissions by 2030 as described in SB 19-236. This will be achieved by establishing extended connections between renewable energy resource zones to the load centers. These connections are critical to the reliable and efficient delivery of future energy resources into the transmission system.

The benefits of energy storage technologies are ever evolving and undisputable in certain scenarios. In most cases, their capabilities are better suited to augment existing transmission assets by enabling load management, opportunity to store excess resources, and voltage support.

Of the many capabilities and applications of energy storage, there is not a relevant energy storage application suitable to deliver the resources from the remote energy resource zones into the centralized load centers. In most cases, the energy resource zones reside along the Colorado – Kansas state border. The problem of delivery can only be addressed by the physical connections from the resource zones into the areas that will consume the resource and thus energy storage technology or a non-wire alternative are inadequate solutions to the identified carbon reduction needs.

While energy storage technologies and their unique capabilities to enhance existing transmission systems will continue to be evaluated by Transmission Providers for potential use in future transmission projects, wide deployment of energy storage was not employed for purposes of this study as it does not offer a realistic or practical alternative to wires-based transmission. Bidders will, however, have the opportunity to submit solar plus storage projects in PSCo's upcoming ERP.

X. Selection of Preferred Alternatives

Alternatives were evaluated based on Study objectives stated in Section III, which include the project's ability to:

- Facilitate transmission access to new clean energy resources[13] in Eastern Colorado located in or near designated ERZs 2 & 3 identified as per SB07-100.
- Enable delivery of electric power output from new clean energy resources located in or near designated ERZs 1, 2, 3 & 5 to the load centers along the Front Range.
- Provide new interconnection points to facilitate development of new clean energy resources located in or near ERZs 1, 2, 3 & 5.
- Achieve adequate reliability and operational flexibility of the resulting interconnected transmission system in Colorado for enabling significantly increased penetration of new clean energy resources sufficient to meet the 80x30TF objectives.

Additional consideration was given to the ability for each Alternative to optimize the reliable integration of at least 3000 MW dispatched incremental renewable resource additions through resource geographic diversity and minimizing thermal and voltage violations on the existing transmission system. Specific attention was also given to each Alternative's ability to mitigate double circuit common tower outages (NERC Category P7).

While each Alternative considered would accommodate 3000 MW of generation, based on the study objectives, resource geographic diversity and minimizing thermal and voltage violations on the underlying transmission system, two alternatives, Alternative 3 and Alternative 7, emerged as the top performers and were thereby selected as the recommended preferred Alternatives, depending on utility participation. On a standalone basis, Alternative 3 was the recommended alternative to serve PSCo's

[13] As defined by SB19-236, "Clean Energy Resource" means any electricity-generating technology that generates or stores electricity without emitting carbon dioxide into the atmosphere. Clean energy resources include, without limitation, eligible energy resources as defined in Section 40-2-124(1)(a).

80x30 carbon reduction objectives. As a joint-utility project, Alternative 7 provided comparable benefits in meeting the study objective and was the recommended alternative if Tri-State chooses to participate in the project to meet its Responsible Energy Plan and public policy needs consistent with the timeframes needed to meet certain carbon reduction goals. Specifically, Alternatives 3 and 7 provided the overall best study results from a reliability and resource diversity perspective through the least amount of identified thermal and voltage violations when compared to the other Alternatives. Additionally, Alternatives 3 and 7 provide access to the currently transmission constrained wind generation development area south of Lamar, and the establishment of a reliable looped transmission system configuration and by maintaining capacity under double circuit common tower outages. Further, Alternatives 3 and 7 provide a robust 345 kV backbone to accommodate new generation development in eastern Colorado, subsequently reducing the line mileage for "gen tie" lines developers might otherwise be required to build to access the transmission network.

XI. Injection Capability Analysis

A. Background

Some 80x30TF Stakeholders raised concerns with the generation dispatch methodology used in the analysis. Specifically, stakeholders were concerned generation across eastern Colorado was not dispatched to create stressed system conditions that would be used in traditional generation interconnection and transmission service studies. The concern was that the dispersed generation methodology of dispatching existing generation in the ERZs 1, 2, 3, and 5 at a level lower than 100 percent of its nameplate rating while adding other new generation in the same location/area would not accurately represent new firm generation accommodated by an alternative. Stakeholders desired verification that under Network Resource Interconnection Service Study procedures what injection capability was possible.

To address this concern, an analysis was performed to determine parallel injection capability using Alternative 3 and sensitivities with Alternative 5, 6 and 7.

B. Methodology

The injection study was performed using Alternative 3 and by adding new generators at Cheyenne Ridge and Lamar. Dispatch between the two locations was assumed to be 60 percent atCheyenne Ridge and 40 percent at Lamar. The aggregate output of these generators was increased in 50 MW increments while aggregate generation associated with coal and gas facilities along the Front Range reduced by 50 MW increments. This injection analysis was performed between 0 and 3500 MW. The stopping point for the 345 kV analysis was 3500 MW since no additional coal or gas plants located along the Front Range were available to be dispatched down. Existing units along the Rush Creek Gen-Tie were dispatched at 100 percent and at Pawnee and Comanche were dispatched at 80 percent. Sensitivity analyses were performed networking Alternative 3 and Story, Burlington, and/or Lamar, to reflect Alternatives 5, 6, and 7.

A sensitivity analysis was performed with Alternative 3 at 500 kV. The 500kV analysis was performed between 0-5000 MW, however between 3500-5000 MW, existing renewables along the Front Range were reduced in order to stress the power transfer limits from the periphery of the system.

In all scenarios, 'large' reactive devices were placed at specific buses to regulate voltage and improve simulation results. The devices were placed at the following locations with the following voltage set-points.

Table 4: Reactive Power Injection Locations and Voltage Setpoints

345 kV System	500 kV System	Voltage Setpoint (PU)
St. Vrain	St. Vrain	1.00
Cheyenne Ridge East	Cheyenne Ridge East	1.02
Lamar	Lamar	1.02
Tundra	Tundra	1.00
Harvest Mile	---	1.00

C. Results

Across all the alternatives and scenarios, there were no significant overloads associated with the transfer of energy from the Cheyenne Ridge and Lamar generation hubs to the Front Range transmission system. The bulk of the overloads occurred in the Denver Metro area, similar to the 80x30 Carbon Reduction Goal Analysis discussed previously but are due to the lack of local Denver Metro generation and the consequential higher imports, rather than the transfer itself.

Reactive power requirements needed to maintain acceptable system voltage is the larger driver on the injection limits, indicating the potential for stability limitations. At the higher end of the studied injection levels, the reactive power requirements to achieve the setpoint values in the table above are significant. Notably, the reactive devices are attempting to hold the voltage setpoint, if those values were able to operate within a specified band the size of the reactive power injection could be reduced. However, this reduction does not come without risk as lower operating N-0 and N-1 voltages place the system closer to a stability limit.

The sensitivities networking at Story, Lamar, and Burlington demonstrated the following:

- Networking at Story
  - Slight reductions in Denver Metro overloads
  - Improved system voltages
- Networking at Lamar
  - Slight reductions in Denver Metro overloads
  - Improved system voltages
  - Corrects/fixes existing reliability concerns in the Lamar area
  - Terminal Upgrades required on:
    - Boone – Lamar 230 kV
    - Lamar – Willow Ck – Lamar bus tie 115 kV
  - Cross-trip RAS needed for loss of both Lamar – Tundra 345 kV lines
    - Low likelihood NERC P6/P7 event
- Networking at Burlington
  - Slight reductions in Denver Metro overloads
  - Improved system voltages
  - Significant Network Upgrades required on underlying system

The slight reduction in overloads and improved system voltage illustrates the benefits of a higher degree of networking on the transmission system. Also, the 500 kV sensitivity showed possible higher injection levels with reduced capacitive reactive power requirements.

XII. General Conclusions

The results of the study indicate that a new wide-area 345 kV transmission project interconnecting at many locations in the Northeastern, Eastern, and Southern portions of the transmission system, and into the Denver Metro area, can accommodate potential generation necessary to meet the state's 2030 carbon reduction goals. The project would create a new Cheyenne Ridge to Pawnee to Fort St. Vrain double circuit 345 kV line, Lamar Area to Tundra to Harvest Mile 345 kV double circuit line, and a Cheyenne Ridge to Lamar Area 345 kV double circuit line, providing efficient and cost-effective access to renewable generation located in ERZs 1, 2, 3, and 5.

Alternatives 3 and 7 are transmission projects identified by the study that would significantly improve the reliability of the Colorado transmission network. Alternative 3 would improve reliability by providing additional high voltage transmission through the eastern portion of Colorado by providing greater access to and support of the existing transmission currently serving the Denver Metro area. Alternative 3 could be modified to add interconnections at Story, Burlington, and/or Lamar as shown in Alternatives 5, 6, and 7 should other Transmission Providers choose to utilize a portion of the project to meet their public policy needs.

The project can also be constructed in stages in order to accommodate the anticipated interconnection of projects in the upcoming resource acquisitions of utilities and the ability to capture available federal tax credits.

XIII. Appendix A

Table 5: Generation Dispatch in Benchmark Study Case

Bus Number	Bus Name	Area	Area Name	In Service	Pgen BM-Alt 1	Pgen Alt2-7	Pmax	Qgen	Qmax
70010	TBII_GEN 0.6900	70	PSCOLORADO	1	78	78	78	-6	25
70017	SI_GEN 0.6000	70	PSCOLORADO	1	15	15	30	-3	15
70069	CABCRKA 13.800	70	PSCOLORADO	1	150	150	162	40	41
70070	CABCRKB 13.800	70	PSCOLORADO	0	150	150	162	23	43
70074	80X30_GV 34.500	70	PSCOLORADO	0	0	0	215	36	72
70074	80X30_GV 34.500	70	PSCOLORADO	0	0	0	285	36	95
70075	80X30_CAMEO 34.500	70	PSCOLORADO	0	0	0	21	-6	7
70075	80X30_CAMEO 34.500	70	PSCOLORADO	0	0	0	29	-10	10
70077	BOONE_CEP 34.500	70	PSCOLORADO	1	91	91	113	34	34
70082	80X30_BOON 34.500	70	PSCOLORADO	0	0	0	43	5	14
70082	80X30_BOON 34.500	70	PSCOLORADO	0	0	0	57	5	19
70104	CHEROK2 15.500	70	PSCOLORADO	1	0	0	0	48	110
70105	80X30_CHER 22.000	70	PSCOLORADO	0	0	0	250	50	125
70105	80X30_CHER 22.000	70	PSCOLORADO	0	97	97	108	36	36
70105	80X30_CHER 22.000	70	PSCOLORADO	0	73	73	142	47	47
70106	CHEROK4 22.000	70	PSCOLORADO	0	350	350	383	119	229
70145	CHEROKEE5 18.000	70	PSCOLORADO	1	100	100	185	58	96
70146	CHEROKEE6 18.000	70	PSCOLORADO	1	100	100	185	95	95
70147	CHEROKEE7 18.000	70	PSCOLORADO	1	150	150	228	82	128
70180	FRUITA 13.800	70	PSCOLORADO	0	18	18	20	1	7
70188	FTLUP1-2 13.800	70	PSCOLORADO	0	40	40	44	-2	31
70188	FTLUP1-2 13.800	70	PSCOLORADO	0	40	40	50	-2	33
70189	80X30_FTLUP 22.000	70	PSCOLORADO	0	0	0	400	-133	133
70189	80X30_FTLUP 22.000	70	PSCOLORADO	0	0	0	172	-57	57
70189	80X30_FTLUP 22.000	70	PSCOLORADO	0	0	0	228	-76	76
70264	80X30_MIDW 34.500	70	PSCOLORADO	0	0	0	43	7	14
70264	80X30_MIDW 34.500	70	PSCOLORADO	0	0	0	57	7	19
70300	MIDWY_CEP 34.500	70	PSCOLORADO	1	80	80	100	33	33
70310	PAWNEE 22.000	70	PSCOLORADO	1	327	327	535	115	115
70314	MANCHEF1 16.000	70	PSCOLORADO	0	0	0	140	22	110
70315	MANCHEF2 16.000	70	PSCOLORADO	0	48	48	140	-50	110
70334	PUB_DSLS 4.1600	70	PSCOLORADO	0	0	0	8	0	4
70337	80X30_PAWN 34.500	70	PSCOLORADO	0	100	100	294	75	98
70337	80X30_PAWN 34.500	70	PSCOLORADO	1	100	100	613	187	204
70344	R.F.DSLS 4.1600	70	PSCOLORADO	0	0	0	10	0	4
70406	ST.VR_2 18.000	70	PSCOLORADO	0	120	120	134	56	102
70407	ST.VR_3 18.000	70	PSCOLORADO	0	120	120	124	47	76
70408	ST.VR_4 18.000	70	PSCOLORADO	0	140	140	145	68	86
70409	ST.VRAIN 22.000	70	PSCOLORADO	1	134	134	318	143	143

Bus Number	Bus Name	Area	Area Name	In Service	Pgen BM-Alt 1	Pgen Alt2-7	Pmax	Qgen	Qmax
70440	80X30_UINTAH34.500	70	PSCOLORADO	0	0	0	21	-1	7
70440	80X30_UINTAH34.500	70	PSCOLORADO	0	0	0	29	-1	10
70448	VALMONT6 13.800	70	PSCOLORADO	0	50	50	57	-4	32
70485	ALMSACT1 13.800	70	PSCOLORADO	0	0	0	19	0	14
70486	ALMSACT2 13.800	70	PSCOLORADO	0	0	0	19	0	14
70487	JMSHAFR4 13.800	70	PSCOLORADO	1	35	35	35	11	28
70487	JMSHAFR4 13.800	70	PSCOLORADO	1	33	33	33	11	31
70490	JMSHAFR3 13.800	70	PSCOLORADO	1	36	36	36	27	30
70490	JMSHAFR3 13.800	70	PSCOLORADO	0	0	0	50	9	9
70493	JMSHAFR2 13.800	70	PSCOLORADO	0	0	0	51	8	9
70495	JMSHAFR1 13.800	70	PSCOLORADO	1	36	36	36	11	31
70495	JMSHAFR1 13.800	70	PSCOLORADO	1	35	35	35	11	31
70498	QF_BCP2T 13.800	70	PSCOLORADO	0	0	0	34	-3	14
70498	QF_BCP2T 13.800	70	PSCOLORADO	0	0	0	36	-5	24
70499	QF_B4-4T 13.800	70	PSCOLORADO	0	20	20	24	-6	15
70499	QF_B4-4T 13.800	70	PSCOLORADO	0	20	20	25	-6	15
70500	QF_CPP1T 13.800	70	PSCOLORADO	0	24	24	24	6	13
70500	QF_CPP1T 13.800	70	PSCOLORADO	0	24	24	24	6	13
70501	QF_CPP3T 13.800	70	PSCOLORADO	0	25	25	27	6	15
70502	PIONEER_IR_S34.500	70	PSCOLORADO	1	52	52	80	-6	26
70548	APT_DSLS 4.1600	70	PSCOLORADO	0	0	0	10	0	4
70553	ARAP5&6 13.800	70	PSCOLORADO	0	38	38	39	-16	39
70553	ARAP5&6 13.800	70	PSCOLORADO	0	38	38	40	-16	40
70554	ARAP7 13.800	70	PSCOLORADO	0	46	46	47	-10	37
70556	QF_B4D4T 12.500	70	PSCOLORADO	0	60	60	70	-6	35
70557	VALMNT7 13.800	70	PSCOLORADO	0	40	40	42	-11	32
70558	VALMNT8 13.800	70	PSCOLORADO	0	40	40	42	8	32
70559	80X30_VALM 34.500	70	PSCOLORADO	0	0	0	108	36	36
70559	80X30_VALM 34.500	70	PSCOLORADO	0	0	0	142	47	47
70560	LAMAR_DC 230.00	70	PSCOLORADO	0	100	100	210	9	50
70561	80X30_SPRUCE34.500	70	PSCOLORADO	0	265	265	294	67	98
70561	80X30_SPRUCE34.500	70	PSCOLORADO	0	460	460	613	117	204
70562	80X30_SPRUCE18.000	70	PSCOLORADO	0	0	0	250	47	83
70563	80X30_SPRUCE18.000	70	PSCOLORADO	0	0	0	200	67	67
70565	KNUTSON1 13.800	70	PSCOLORADO	1	49	49	68	45	45
70566	KNUTSON2 13.800	70	PSCOLORADO	1	49	49	68	45	45
70577	FTNVL1&2 13.800	70	PSCOLORADO	0	35	35	40	11	27
70577	FTNVL1&2 13.800	70	PSCOLORADO	0	35	35	40	11	28
70578	FTNVL3&4 13.800	70	PSCOLORADO	0	34	34	40	21	24
70578	FTNVL3&4 13.800	70	PSCOLORADO	0	35	35	40	12	27
70579	FTNVL5&6 13.800	70	PSCOLORADO	0	35	35	40	12	26

Bus Number	Bus Name	Area	Area Name	In Service	Pgen BM-Alt 1	Pgen Alt2-7	Pmax	Qgen	Qmax
70579	FTNVL5&6 13.800	70	PSCOLORADO	0	35	35	40	12	28
70580	PLNENDG1_1 13.800	70	PSCOLORADO	0	5	5	5	1	2
70580	PLNENDG1_1 13.800	70	PSCOLORADO	0	5	5	5	1	2
70580	PLNENDG1_1 13.800	70	PSCOLORADO	0	5	5	5	1	2
70580	PLNENDG1_1 13.800	70	PSCOLORADO	0	5	5	5	1	2
70580	PLNENDG1_1 13.800	70	PSCOLORADO	0	5	5	5	1	2
70580	PLNENDG1_1 13.800	70	PSCOLORADO	0	5	5	5	1	2
70580	PLNENDG1_1 13.800	70	PSCOLORADO	0	5	5	5	1	2
70580	PLNENDG1_1 13.800	70	PSCOLORADO	0	5	5	5	1	2
70580	PLNENDG1_1 13.800	70	PSCOLORADO	0	5	5	5	1	2
70580	PLNENDG1_1 13.800	70	PSCOLORADO	0	5	5	5	1	2
70585	PLNENDG2_1 13.800	70	PSCOLORADO	0	8	8	8	0	2
70585	PLNENDG2_1 13.800	70	PSCOLORADO	0	8	8	8	0	2
70585	PLNENDG2_1 13.800	70	PSCOLORADO	0	8	8	8	0	2
70585	PLNENDG2_1 13.800	70	PSCOLORADO	0	8	8	8	0	2
70585	PLNENDG2_1 13.800	70	PSCOLORADO	0	8	8	8	0	2
70585	PLNENDG2_1 13.800	70	PSCOLORADO	0	8	8	8	0	2
70585	PLNENDG2_1 13.800	70	PSCOLORADO	0	8	8	8	0	2
70586	PLNENDG2_2 13.800	70	PSCOLORADO	0	8	8	8	0	2
70586	PLNENDG2_2 13.800	70	PSCOLORADO	0	8	8	8	0	2
70586	PLNENDG2_2 13.800	70	PSCOLORADO	0	8	8	8	0	2
70586	PLNENDG2_2 13.800	70	PSCOLORADO	0	8	8	8	0	2
70586	PLNENDG2_2 13.800	70	PSCOLORADO	0	8	8	8	0	2
70586	PLNENDG2_2 13.800	70	PSCOLORADO	0	8	8	8	0	2
70586	PLNENDG2_2 13.800	70	PSCOLORADO	0	8	8	8	0	2
70587	PLNENDG1_2 13.800	70	PSCOLORADO	0	5	5	5	0	2
70587	PLNENDG1_2 13.800	70	PSCOLORADO	0	5	5	5	0	2
70587	PLNENDG1_2 13.800	70	PSCOLORADO	0	5	5	5	0	2
70587	PLNENDG1_2 13.800	70	PSCOLORADO	0	5	5	5	0	2
70587	PLNENDG1_2 13.800	70	PSCOLORADO	0	5	5	5	0	2
70587	PLNENDG1_2 13.800	70	PSCOLORADO	0	5	5	5	0	2
70587	PLNENDG1_2 13.800	70	PSCOLORADO	0	5	5	5	0	2
70587	PLNENDG1_2 13.800	70	PSCOLORADO	0	5	5	5	0	2
70587	PLNENDG1_2 13.800	70	PSCOLORADO	0	5	5	5	0	2
70587	PLNENDG1_2 13.800	70	PSCOLORADO	0	5	5	5	0	2
70588	RMEC1 15.000	70	PSCOLORADO	0	125	125	142	57	57
70589	RMEC2 15.000	70	PSCOLORADO	0	125	125	151	12	65
70591	RMEC3 23.000	70	PSCOLORADO	0	300	300	313	11	123
70593	SPNDLE1 18.000	70	PSCOLORADO	0	140	140	143	48	109
70594	SPNDLE2 18.000	70	PSCOLORADO	0	140	140	141	48	102
70595	80X30_HARV-M34.500	70	PSCOLORADO	0	265	265	294	52	98

Bus Number	Bus Name	Area	Area Name	In Service	Pgen BM-Alt 1	Pgen Alt2-7	Pmax	Qgen	Qmax
70595	80X30_HARV-M34.500	70	PSCOLORADO	0	460	460	613	90	204
70602	80X30_CYR1 34.500	70	PSCOLORADO	1	0	625	833	105	277
70602	80X30_CYR1 34.500	70	PSCOLORADO	1	0	625	833	105	277
70602	80X30_CYR1 34.500	70	PSCOLORADO	0	625	625	833	111	277
70602	80X30_CYR1 34.500	70	PSCOLORADO	0	625	625	833	111	277
70603	80X30_PAWN 34.500	70	PSCOLORADO	0	125	125	833	268	277
70603	80X30_PAWN 34.500	70	PSCOLORADO	0	625	625	833	146	277
70603	80X30_PAWN 34.500	70	PSCOLORADO	1	625	0	833	115	277
70603	80X30_PAWN 34.500	70	PSCOLORADO	1	625	0	833	115	277
70616	TITAN_S1 0.6300	70	PSCOLORADO	1	45	45	50	-6	16
70622	80X30_MS 34.500	70	PSCOLORADO	0	100	100	294	11	98
70622	80X30_MS 34.500	70	PSCOLORADO	1	100	100	613	48	204
70629	RUSHCK_W1 34.500	70	PSCOLORADO	1	157	157	380	-1	132
70631	RUSHCK_W2 34.500	70	PSCOLORADO	1	91	91	220	-15	41
70633	CEP_2 34.500	70	PSCOLORADO	1	124	124	300	95	99
70635	LIMON1_W 34.500	70	PSCOLORADO	1	83	83	201	-12	66
70636	LIMON2_W 34.500	70	PSCOLORADO	1	83	83	201	-11	66
70637	LIMON3_W 34.500	70	PSCOLORADO	1	83	83	201	-14	66
70646	CHEYNRD_W 34.500	70	PSCOLORADO	1	96	96	232	77	77
70647	CHEYNRD_E 34.500	70	PSCOLORADO	1	110	110	268	88	88
70653	CEP_5 34.500	70	PSCOLORADO	1	161	161	200	62	66
70665	JKFUL_W1 0.6900	70	PSCOLORADO	1	46	46	124	29	41
70666	JKFUL_W2 0.6900	70	PSCOLORADO	1	46	46	125	24	41
70670	CEDARPT_W1 0.6900	70	PSCOLORADO	1	51	51	124	0	0
70671	CEDARPT_W2 0.6900	70	PSCOLORADO	1	52	52	126	0	0
70696	EVRAZ_CEP 34.500	70	PSCOLORADO	1	193	193	240	16	80
70701	CO_GRN_E 34.500	70	PSCOLORADO	1	81	81	81	26	26
70702	CO_GRN_W 34.500	70	PSCOLORADO	1	81	81	81	26	26
70703	TWNBUTTE 34.500	70	PSCOLORADO	1	65	65	65	1	26
70710	PTZLOGN1 34.500	70	PSCOLORADO	1	158	158	201	5	66
70712	PTZLOGN2 34.500	70	PSCOLORADO	1	50	50	120	0	39
70713	PTZLOGN3 34.500	70	PSCOLORADO	1	33	33	80	1	26
70714	PTZLOGN4 34.500	70	PSCOLORADO	1	72	72	175	17	49
70721	SPRNGCAN 0.5700	70	PSCOLORADO	0	49	49	65	-14	31
70723	RDGCREST 34.500	70	PSCOLORADO	1	12	12	30	0	0
70726	SPANPKS2_GEN0.6300	70	PSCOLORADO	0	0	0	40	0	23
70777	COMAN_3 27.000	70	PSCOLORADO	1	522	522	780	257	257
70778	CEP_6 34.500	70	PSCOLORADO	1	201	201	250	82	82
70819	CEP_3 34.500	70	PSCOLORADO	1	127	127	169	55	55
70823	CEDARCK_1A 34.500	70	PSCOLORADO	1	165	165	220	49	49
70824	CEDARCK_1B 34.500	70	PSCOLORADO	1	60	60	80	64	66

Bus Number	Bus Name	Area	Area Name	In Service	Pgen BM-Alt 1	Pgen Alt2-7	Pmax	Qgen	Qmax
70825	CEDAR2_W1 0.6600	70	PSCOLORADO	1	94	94	125	13	43
70826	CEDAR2_W2 0.6900	70	PSCOLORADO	1	76	76	101	-14	25
70827	CEDAR2_W3 0.6600	70	PSCOLORADO	1	19	19	25	9	9
70900	80X30_HUSKY 34.500	70	PSCOLORADO	0	0	0	50	16	16
70923	80X30_HARTSE34.500	70	PSCOLORADO	0	0	0	21	1	7
70923	80X30_HARTSE34.500	70	PSCOLORADO	0	0	0	29	1	10
70928	CEP_7 34.500	70	PSCOLORADO	1	72	72	72	0	0
70929	80X30_COMA 34.500	70	PSCOLORADO	0	0	0	207	10	69
70929	80X30_COMA 34.500	70	PSCOLORADO	0	0	0	275	13	92
70931	GSANDHIL_PV 34.500	70	PSCOLORADO	1	17	17	19	0	0
70932	SLV_PV 34.500	70	PSCOLORADO	1	27	27	30	0	0
70933	COGENTRIX_PV34.500	70	PSCOLORADO	1	27	27	30	0	0
70934	COMAN_S1 0.4180	70	PSCOLORADO	1	100	100	125	14	52
70935	HOOPER_PV 34.500	70	PSCOLORADO	1	47	47	52	0	0
70950	ST.VR_5 18.000	70	PSCOLORADO	0	130	130	157	18	46
70951	ST.VR_6 18.000	70	PSCOLORADO	0	130	130	157	42	46
70952	80X30_FSV 34.500	70	PSCOLORADO	0	0	0	215	65	72
70952	80X30_FSV 34.500	70	PSCOLORADO	0	0	0	285	22	95
70953	80X30_Tundra	70	PSCOLORADO	1	500	0	1000	149	333
70953	80X30_Tundra	70	PSCOLORADO	1	500	0	1000	149	333
70953	80X30_Lamar	70	PSCOLORADO	1	0	500	1000	149	333
70953	80X30_Lamar	70	PSCOLORADO	1	0	500	1000	149	333
70954	80X30_COM23034.500	70	PSCOLORADO	1	450	450	800	105	267
70956	80X30_MID23034.500	70	PSCOLORADO	0	0	0	800	43	267
70958	80X30_BON23034.500	70	PSCOLORADO	0	0	0	300	18	100
70994	TI-18-0809 0.6300	70	PSCOLORADO	1	100	100	100	39	59
71001	BAC_MSA GEN113.800	70	PSCOLORADO	1	91	91	90	2	21
71002	BAC_MSA GEN213.800	70	PSCOLORADO	1	91	91	90	3	21
71003	BAC_MSA GEN413.800	70	PSCOLORADO	1	40	40	40	0	40
71003	BAC_MSA GEN413.800	70	PSCOLORADO	1	40	40	40	0	40
71003	BAC_MSA GEN413.800	70	PSCOLORADO	1	25	25	25	0	16
71004	BAC_MSA GEN513.800	70	PSCOLORADO	1	40	40	40	1	40
71004	BAC_MSA GEN513.800	70	PSCOLORADO	1	40	40	40	1	40
71004	BAC_MSA GEN513.800	70	PSCOLORADO	1	25	25	25	1	16
71005	BAC_MSA GEN613.800	70	PSCOLORADO	1	40	40	40	0	25
71009	BUSCHRWTG1 0.7000	70	PSCOLORADO	1	4	4	29	-5	9
71013	BUSCHRNCH_LO0.7000	70	PSCOLORADO	1	20	20	59	1	19
71016	PEAKVIEWLO 0.7000	70	PSCOLORADO	1	10	10	60	-3	27
72004	PANO_GEN 0.7000	73	PSCOLORADO	0	0	0	149	0	49
72703	CRSL_GEN 0.7000	73	PSCOLORADO	1	131	131	150	-9	77
72714	KC_GEN 0.7000	73	PSCOLORADO	1	40	40	51	-3	17

Bus Number	Bus Name	Area	Area Name	In Service	Pgen BM-Alt 1	Pgen Alt2-7	Pmax	Qgen	Qmax
72719	CT_GEN 0.7000	73	PSCOLORADO	1	75	75	104	10	50
72724	AXIAL_GEN 0.6300	73	PSCOLORADO	0	0	0	145	0	57
72729	DOLORES_GEN 0.6300	73	PSCOLORADO	0	0	0	110	0	44
72739	NIYOL_GEN 0.6300	73	PSCOLORADO	0	0	0	200	0	97
72746	COYOTE_GEN 0.6300	73	PSCOLORADO	0	0	0	120	0	47
73054	ELBERT-1 11.500	73	PSCOLORADO	1	90	90	103	3	3
73129	MBPP-1 24.000	73	PSCOLORADO	1	903	903	605	205	275
73130	MBPP-2 24.000	73	PSCOLORADO	1	600	600	605	205	275
73181	SIDNEYDC 230.00	73	PSCOLORADO	1	200	200	200	-210	-90
73226	YELLO1-2 13.800	73	PSCOLORADO	1	60	60	65	18	39
73226	YELLO1-2 13.800	73	PSCOLORADO	1	60	60	65	18	39
73227	YELLO3-4 13.800	73	PSCOLORADO	1	70	70	76	13	39
73227	YELLO3-4 13.800	73	PSCOLORADO	1	60	60	65	11	39
73289	RCCT1 13.800	73	PSCOLORADO	1	17	17	17	-3	15
73291	RCCT2 13.800	73	PSCOLORADO	1	17	17	17	-3	15
73292	RCCT3 13.800	73	PSCOLORADO	1	17	17	17	-3	15
73293	RCCT4 13.800	73	PSCOLORADO	1	17	17	17	-3	15
73299	BIGTHOMP 4.2000	73	PSCOLORADO	1	3	3	5	0	0
73302	BRLNGTN1 13.800	73	PSCOLORADO	1	25	25	48	-9	44
73303	BRLNGTN2 13.800	73	PSCOLORADO	1	25	25	48	-9	44
73306	ESTES1 6.9000	73	PSCOLORADO	1	10	10	16	12	12
73307	ESTES2 6.9000	73	PSCOLORADO	1	10	10	16	13	13
73308	ESTES3 6.9000	73	PSCOLORADO	1	10	10	16	13	13
73316	GREENMT1 6.9000	73	PSCOLORADO	1	9	9	14	1	31
73317	GREENMT2 6.9000	73	PSCOLORADO	1	9	9	14	1	10
73319	MARYLKPP 6.9000	73	PSCOLORADO	1	7	7	10	-6	7
73324	POLEHILL 13.800	73	PSCOLORADO	1	32	32	38	23	23
73328	WILLMFRK 2.4000	73	PSCOLORADO	1	1	1	3	0	0
73332	ALCOVA1 6.9000	73	PSCOLORADO	1	15	15	20	6	10
73333	BOYSEN1 4.2000	73	PSCOLORADO	1	5	5	8	-1	4
73333	BOYSEN1 4.2000	73	PSCOLORADO	1	5	5	8	-1	4
73334	BBILL1-2 6.9000	73	WAPA R.M.	1	4	4	7	2	3
73334	BBILL1-2 6.9000	73	WAPA R.M.	1	4	4	7	2	3
73339	HEART MT 2.4000	73	WAPA R.M.	1	4	4	7	4	4
73341	NSS2 13.800	73	WAPA R.M.	1	91	91	88	5	23
73347	SHOSHONE 6.9000	73	WAPA R.M.	1	2	2	3	2	2
73349	FREMONT1 11.500	73	WAPA R.M.	1	28	28	33	-3	21
73350	FREMONT2 11.500	73	WAPA R.M.	1	28	28	33	-3	22
73351	GLENDO1 6.9000	73	WAPA R.M.	1	15	15	19	2	2
73352	GLENDO2 6.9000	73	WAPA R.M.	1	15	15	19	2	2
73353	GUERNSY1 2.4000	73	WAPA R.M.	1	2	2	3	2	2

Bus Number	Bus Name	Area	Area Name	In Service	Pgen BM-Alt 1	Pgen Alt2-7	Pmax	Qgen	Qmax
73356	KORTES1 6.9000	73	WAPA R.M.	1	8	8	14	2	8
73357	KORTES2 6.9000	73	WAPA R.M.	1	8	8	14	2	6
73358	KORTES3 6.9000	73	WAPA R.M.	1	8	8	14	2	6
73363	SEMINOE1-2 6.9000	73	WAPA R.M.	1	10	10	15	0	8
73363	SEMINOE1-2 6.9000	73	WAPA R.M.	1	10	10	15	0	8
73438	ALCOVA2 6.9000	73	WAPA R.M.	1	15	15	20	6	9
73439	BBILL3-4 6.9000	73	WAPA R.M.	1	4	4	7	2	3
73441	SEMINOE3 6.9000	73	WAPA R.M.	1	10	10	15	-1	8
73444	GUERNSY2 2.4000	73	WAPA R.M.	1	2	2	3	2	2
73448	FLATIRN1 13.800	73	WAPA R.M.	1	42	42	48	26	27
73449	FLATIRN2 13.800	73	WAPA R.M.	1	42	42	48	26	27
73449	FLATIRN2 13.800	73	WAPA R.M.	1	7	7	9	0	0
73461	ELBERT-2 11.500	73	WAPA R.M.	1	90	90	103	33	33
73462	SPIRTMTN 6.9000	73	WAPA R.M.	1	4	4	5	3	3
73520	BFDIESEL 4.2000	73	WAPA R.M.	0	0	0	10	3	9
73532	LINCOLN1 13.800	73	WAPA R.M.	1	40	40	69	-3	47
73533	LINCOLN2 13.800	73	WAPA R.M.	1	40	40	63	-3	47
73631	COHIWND_G1 0.7000	73	WAPA R.M.	1	60	60	67	0	33
73635	COHIWND_G2 0.7000	73	WAPA R.M.	1	23	23	23	9	10
74014	NSS_CT1 13.800	73	WAPA R.M.	1	40	40	37	-8	9
74015	NSS_CT2 13.800	73	WAPA R.M.	1	23	23	37	-8	11
74016	WYGEN 13.800	73	WAPA R.M.	1	93	93	95	13	29
74017	WYGEN2 13.800	73	WAPA R.M.	1	100	100	100	0	8
74018	WYGEN3 13.800	73	WAPA R.M.	1	110	110	115	15	38
74029	LNG_CT1 13.800	73	WAPA R.M.	1	40	40	37	-6	16
74042	CLR_1 0.6000	73	WAPA R.M.	1	20	20	29	-3	1
74043	SS_GEN1 0.6000	73	WAPA R.M.	1	27	27	42	-5	2
74053	BC_DVAR 0.5000	73	WAPA R.M.	0	0	0	0	0	0
74061	CPGSTN_1 13.800	73	WAPA R.M.	1	40	40	37	6	44
74061	CPGSTN_1 13.800	73	WAPA R.M.	1	40	40	37	6	32
74061	CPGSTN_1 13.800	73	WAPA R.M.	1	25	25	21	4	16
74062	CPGSTN_2 13.800	73	WAPA R.M.	1	40	40	37	12	20
74063	CPGSTN_3 13.800	73	WAPA R.M.	1	43	43	50	7	39
74063	CPGSTN_3 13.800	73	WAPA R.M.	1	43	43	50	7	39
74063	CPGSTN_3 13.800	73	WAPA R.M.	1	20	20	25	3	15
76301	ARVADA1 13.800	73	WAPA R.M.	1	7	7	7	-2	5
76302	ARVADA2 13.800	73	WAPA R.M.	1	7	7	7	-2	5
76303	ARVADA3 13.800	73	WAPA R.M.	1	7	7	7	-2	5
76305	BARBERC1 13.800	73	WAPA R.M.	1	7	7	7	1	5
76306	BARBERC2 13.800	73	WAPA R.M.	1	7	7	7	1	5
76307	BARBERC3 13.800	73	WAPA R.M.	1	7	7	7	1	5

Bus Number	Bus Name	Area	Area Name	In Service	Pgen BM-Alt 1	Pgen Alt2-7	Pmax	Qgen	Qmax
76309	HARTZOG1 13.800	73	WAPA R.M.	0	0	0	7	0	5
76310	HARTZOG2 13.800	73	WAPA R.M.	0	0	0	7	0	5
76311	HARTZOG3 13.800	73	WAPA R.M.	1	7	7	7	2	5
76313	TK DVAR1 0.5000	73	WAPA R.M.	1	0	0	1	0	16
76314	TK DVAR2 0.5000	73	WAPA R.M.	1	0	0	1	2	16
76351	RCDC W 230.00	73	WAPA R.M.	1	200	200	200	-10	10
76404	DRYFORK 19.000	73	WAPA R.M.	1	440	440	440	47	260
76502	SPFSHPRK 69.000	73	WAPA R.M.	0	0	0	4	0	0
78011	RAWHIDE 24.000	70	WAPA R.M.	0	300	300	304	84	135
78012	RAWHIDEA 13.800	70	WAPA R.M.	0	60	60	70	-1	32
78013	RAWHIDEB 13.800	70	WAPA R.M.	0	60	60	70	20	32
78014	RAWHIDEC 13.800	70	WAPA R.M.	1	60	60	70	21	32
78015	RAWHIDED 13.800	70	WAPA R.M.	1	60	60	70	23	32
78016	RAWHIDEF 18.000	70	WAPA R.M.	1	120	120	138	41	60
78022	RH_PV_GEN 0.6000	70	WAPA R.M.	1	25	25	32	1	12
78515	FTRNG3CC 21.000	70	WAPA R.M.	1	208	208	208	132	132
78516	RD_NIXON 20.000	70	WAPA R.M.	0	0	0	225	45	45
78517	FTRNG1CC 18.000	70	WAPA R.M.	1	140	140	141	63	63
78518	FTRNG2CC 18.000	70	WAPA R.M.	1	141	141	141	59	59
78519	BIRDSAL1 13.800	70	WAPA R.M.	0	0	0	18	0	14
78520	BIRDSAL2 13.800	70	WAPA R.M.	0	0	0	18	0	14
78521	BIRDSAL3 13.800	70	WAPA R.M.	0	0	0	23	0	20
78522	DRAKE 6 13.800	70	WAPA R.M.	0	0	0	0	51	0
78523	DRAKE 7 13.800	70	WAPA R.M.	0	0	0	0	48	0
78524	TESLA1 13.800	70	WAPA R.M.	1	24	24	28	-5	3
78525	NIXONCT1 12.500	70	WAPA R.M.	0	0	0	27	0	24
78526	NIXONCT2 12.500	70	WAPA R.M.	0	0	0	27	0	22
78527	PIKE_PVPLANT0.6000	70	WAPA R.M.	1	89	89	175	18	40
78528	GYAK_PV1 0.6000	70	WAPA R.M.	1	18	18	35	15	15
78529	WC_PVPLANT 0.6300	70	WAPA R.M.	1	30	30	60	5	30
78537	TNGG_A 13.800	70	WAPA R.M.	1	27	27	27	5	13
78537	TNGG_A 13.800	70	WAPA R.M.	1	27	27	27	5	13
78537	TNGG_A 13.800	70	WAPA R.M.	1	27	27	27	5	13
78538	TNGG_B 13.800	70	WAPA R.M.	1	27	27	27	7	13
78538	TNGG_B 13.800	70	WAPA R.M.	1	27	27	27	7	13
78541	PIKE_BESS 0.6000	70	WAPA R.M.	1	25	25	25	5	12
78543	TNGG_FC 13.800	70	WAPA R.M.	1	27	27	27	-5	13
78656	BRIARGATE N 115.00	70	WAPA R.M.	1	25	25	25	12	12
78863	HORIZON 230.00	70	WAPA R.M.	1	31	31	117	60	60
79015	80X30_CRAIG 34.500	73	WAPA R.M.	0	0	0	147	-12	49
79015	80X30_CRAIG 34.500	73	WAPA R.M.	0	0	0	195	-12	65

Bus Number	Bus Name	Area	Area Name	In Service	Pgen BM-Alt 1	Pgen Alt2-7	Pmax	Qgen	Qmax
79016	CRAIG 2 22.000	73	WAPA R.M.	0	42	42	470	-136	216
79017	CRAIG 3 22.000	73	WAPA R.M.	0	478	478	478	-16	145
79019	MORRO1-2 12.500	73	WAPA R.M.	1	75	75	81	-7	59
79019	MORRO1-2 12.500	73	WAPA R.M.	1	75	75	81	-7	60
79033	80X30_HAYDEN34.500	73	WAPA R.M.	0	0	0	192	-2	64
79033	80X30_HAYDEN34.500	73	WAPA R.M.	0	0	0	256	-2	85
79040	HAYDEN1 18.000	73	WAPA R.M.	0	139	139	212	-1	70
79041	HAYDEN2 22.000	73	WAPA R.M.	0	98	98	286	58	130
79055	80X30_RIFLE 34.500	70	WAPA R.M.	0	0	0	172	-10	57
79055	80X30_RIFLE 34.500	70	WAPA R.M.	0	0	0	228	-10	76
79123	FONTNLLE 4.2000	73	WAPA R.M.	1	7	7	11	4	4
79154	FLGORG1 11.500	73	WAPA R.M.	1	50	50	56	-7	38
79155	FLGORG2 11.500	73	WAPA R.M.	1	50	50	56	-7	39
79156	FLGORG3 11.500	73	WAPA R.M.	1	50	50	56	-7	39
79157	BMESA1-2 11.500	73	WAPA R.M.	1	39	39	44	-1	29
79157	BMESA1-2 11.500	73	WAPA R.M.	1	39	39	44	-1	30
79162	CRYSTAL 11.500	73	WAPA R.M.	1	30	30	35	0	18
79164	TOWAOC 6.9000	73	WAPA R.M.	1	8	8	12	-4	7
79166	MOLINA-L 4.2000	73	WAPA R.M.	1	3	3	5	1	2
79172	MOLINA-U 4.2000	73	WAPA R.M.	1	6	6	9	0	4
79176	MCPHEE 2.4000	73	WAPA R.M.	1	1	1	1	0	0
79251	QFATLAS1 13.800	73	WAPA R.M.	1	30	30	31	-4	22
79251	QFATLAS1 13.800	73	WAPA R.M.	1	15	15	15	-2	11
79252	QFATLAS2 13.800	73	WAPA R.M.	1	15	15	15	-4	11
79252	QFATLAS2 13.800	73	WAPA R.M.	1	15	15	15	-4	11
740039	TRK_CRK LO 0.6000	70	WAPA R.M.	1	200	200	206	29	100

XIV. Appendix B

Table 6: Overloads Shown in Benchmark and Alternative Cases

Overloaded Facility	Region	Type	OH/UG	Owner	Base Case Rating (MVA)	Contingency	80x30TF Benchmark	80x30TF Alt 1	80x30TF Alt 2	80x30TF Alt 3	80x30TF Alt 4	80x30TF Alt 5	80x30TF Alt 6	80x30TF Alt 7
Greenwood-Monaco 230	Metro	Line	OH/UG	PSCo	503*	Buckley2-Smoky Hill 230	N-0 OL	123%	123%	129%	127%	128%	128%	131%
Monaco-Sullivan 230	Metro	Line	OH/UG	PSCo	470*	Buckley-Smoky Hill 230	N-0 OL	125%	125%	131%	129%	129%	130%	132%
Leetsdale-Sullivan 230	Metro	Line	OH/UG	PSCo	396	Buckley-Smoky Hill 230	126%	102%	102%	108%	106%	107%	107%	109%
Buckley-Tollgate 230	Metro	Line	OH	PSCo	484	Greenwood-Monaco 230	125%	113%	113%	119%	118%	118%	118%	119%
Buckley-Smoky Hill 230	Metro	Line	OH	PSCo	506	Greenwood-Monaco 230	119%	108%	108%	114%	113%	113%	113%	114%
Leetsdale-Monroe 230	Metro	Line	UG	PSCo	396	Daniels Park-Santa Fe 230	N-0 OL	107%	107%	116%	112%	113%	114%	116%
Leetsdale-Harrison 115 kV	Metro	Line	UG	PSCo	141	Leetsdale-Monroe 230 kV	121%			105%	103%	103%	103%	106%
Daniels Park-Prairie #1 230	Metro	Line	OH	PSCo	576*	Daniels Park-Prairie #2 230	146%	109%	109%	110%	108%	110%	109%	114%
Daniels Park-Prairie #2 230	Metro	Line	OH	PSCo	576*	Daniels Park-Prairie #1 230	145%	108%	108%	109%	108%	109%	109%	113%
Greenwood-Prairie # 1 230 kV	Metro	Line	OH	PSCo	576*	Daniels Park-Prairie #1 230 kV	134%			129%	127%	128%	128%	102%
Greenwood-Prairie #2 230 kV	Metro	Line	OH	PSCo	576*	Daniels Park-Prairie #2 230 kV	136%			100%				104%
Havana1-Chambers 115	Metro	Line	OH	PSCo	120	Havana2-Chambers 115	N-0 OL	130%	130%	101%	100%		100%	101%
Waterton-WatertonTP 115	Metro	Line	OH	PSCo	127	Soda Lake 230/115	N-0 OL	118%	118%	136%	134%	135%	135%	139%
Waterton-MartinTP 115	Metro	Line	OH	PSCo	138	Arapahoe 230/115	120%	102%	102%	108%	107%	108%	108%	109%
Daniels Park-Happy Canyon 115	Metro	Line	OH	PSCo	132	Parker-Bayou 115		100%	100%					
WL_Child-Archer 230	Metro	Line	OH	TSGT	637	Ault-LRS 345	N-0 OL	112%	112%	119%	120%	121%		
Arapahoe-Santa Fe 230	Metro	Line	OH	PSCo	319	Arapahoe-Greenwood 230	N-0 OL			103%	101%	101%	102%	105%
Derby 2-Havana 115	Metro	Line	OH	PSCo	120	Havana2-Chambers 115	108%			102%	101%	101%	101%	102%
Arap_A-Sheridan	Metro	Line	OH	PSCo	127	Ault-LRS 345	101%							
Deer Creek-Soda Lake 115	Metro	Line	OH	PSCo	120	Chatfield-Waterton 230	129%							
Elati-Monroe 230	Metro	Line	OH	PSCo	398	Greenwood-Arapahoe 230	122%							
Ft.Lupton-Pawnee 230	Metro	Line	OH	PSCo	481	Pawnee-Story 230	121%							
Jewell2-Tollgate 230	Metro	Line	OH	PSCo	484	Greenwood-Monaco 230	105%							
Pawnee-Story 230	Metro	Line	OH	PSCo	581	Pawnee-Ft.Lupton 230	129%							
Archer-Terry Ranch 230	Metro	Line	OH	PSCo	442	Ault-LRS 345	111%							
Ault-Terry Ranch 230	Metro	Line	OH	PSCo	457	Ault-LRS 345	111%							
BrushTP-EFMORGTP	Metro	Line	OH	PSCo	160	BeaverCk-Adena 115	104%							
EFMORGTP-FMWest	Metro	Line	OH	PSCo	121	BeaverCk-Adena 115	110%							
Vollmert-Fuller 115 kV	South	Line	OH	CSU	173	Paddock-Falcon 115	121%					100%		103%
FV-MidwayBR 115	South	Line	OH	BHC	115	MidwayBR-RD_Nixon 230	110%	116%	116%					
W.Canon-Hogback 115	South	Line	OH	BHC	120	MidwayBR-W.Canon 230	144%			110%	107%	109%	109%	115%
Midway-W.Station 115	South	Line	OH	BHC	80	Ftn_Lk-North Ridge 115	102%							
MidwayPS-MidwayBR	South	Line	OH	WAPA	430	Midway-Fuller 230	142%							
MidwayPS-Fuller 230	South	Line	OH	PSCo	478	MidwayPS-MidwayBR 230	110%							
PuebloTP-Stem_Beach	South	Line	OH	TSGT	92	Comacnhe-Walsenburg 230	116%							
Blkfortp_Blk_Sqmv	South	Line	OH	CSU	143	Daniels Park-Fuller 230	101%							
Curecant-S.Canal 115	Southwest	Line	OH	WAPA	137	Curecanti-Northfork 230	108%							
Montrose-S.Canal 115	Southwest	Line	OH	WAPA	137	Curecanti-Northfork 230	101%							
Lam_Co-Wilow_Ck 115	Southeast	Line	OH	TSGT	107	Boone-Lamar 230	Blown Up	Blown Up	112%	124%	124%	124%	124%	
LaJuntaW-RockyFrd 69	Southeast	Line	OH	BHC	23	Boone-S.Fowler 115	116%	116%	116%	116%	116%	116%	116%	116%

XV. Appendix C

A. Mark D. Detsky Comments of Independent Power Producers (IPPs) on portfolios of Office of Consumer Counsel (OCC) representative Chris Neil

DIETZE AND DAVIS, P.C.
ATTORNEYS AT LAW
Serving the West from Boulder since 1972

Robyn W. Kube
Karl F. Kumli, III*†
Carmen S. Danielson
Renée Ezer*
Stephen A. Closky
Tucker M. Katz
Mark D. Detsky
Glenn H. Lenzen*
William A. Rogers, III
Joshua E. Anderson
Jennifer L. Lorenz
Gabriella Stockmayer

Siena Square Building
2060 Broadway, Suite 400
Boulder, Colorado 80302
Telephone (303) 447-1375
Fax (303) 440-9036
www.dietzedavis.com

Email: mdetsky@dietzedavis.com

Nathan A. Klotz
K.C. Cunilio
Rachel Bolt

Of Counsel:
Joel C. Maguire
Star L. Waring
David J. Thrower
Nicholas G. Muller

Peter C. Dietze 1934-2019
Joel C. Davis 1936-2013

*Also admitted in California
†*Also admitted in New Mexico*

MEMORANDUM

TO: Colorado Coordinated Planning Group (CCPG) 80 X 30 Task Force

FROM: Mark D. Detsky

DATE: February 22, 2021

SUBJECT: Comments of Independent Power Producers (IPPs) on portfolios of Office of Consumer Counsel (OCC) representative Chris Neil

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Thank you for the opportunity to present a rebuttal to the comments of the OCC's 31 portfolios based on bids submitted to Public Service Company of Colorado (Public Service) in 2017. The IPP coalition would like the 80 X 30 Task Force Report to reflect widespread support from the independent power producer market for this desperately needed transmission expansion in eastern Colorado. The project conceived in this report is an important first step to achieving Colorado's carbon dioxide emission reduction targets that will apply to each of Colorado's load serving transmission providers.

The IPP community expects that these issues will be explored in transmission and resource planning proceedings at the Colorado PUC. However, there are three points the IPP community wishes to raise for the CCPG's consideration in this report:

1. **<u>The OCC's Comments Do Not Reflect the Current or Expected Market Reality</u>**

A large part of Mr. Neil's comments concern the formation of a market connection to the Southwest Power Pool (SPP), and interconnections to the western California Independent System Operator (CAISO) via the TransWest Express project. Mr. Neil's analysis takes these assumptions a step further in relying on the inclusion of an 800 MW AC-DC tie to be located at the Public Service Cheyenne Ridge substation (without any cost estimate), also involving the "reconnection" of a 300 MW wind project with an executed and completed interconnection agreement, and then a 50 – 150 mile line from the TransWest Express project to Colorado which would form an interconnection to the CAISO.

First, the IPP market supports various market structures being pursued in Colorado and agrees with Mr. Neil that market structures could provide many economic benefits. However, Mr. Neil's assumptions for the purpose of his analysis are not realistic to meet a 2030 timeline for the carbon emission goals of Colorado. First, joining one or both of the SPP and CAISO markets is a multi-year process on its own, but then operating within those market structures to study and construct specific ties and upgrades is an additional layer of unknown, but certain, delay. This is especially true in considering a new, large, AC-DC tie to SPP. Such a project would have to not only navigate the SPP transmission planning process, but it would also be subject to market rules between the western and eastern interconnections that include non-synchronous operation, and go through SPP's cost allocation review process. These hurdles are significant, introduce substantial timeline delay, and have not been analyzed in any level of detail from a transmission or cost perspective. Finally, Mr. Neil's analysis of SPP nodal pricing is not reflective of long-term market conditions, but instead represents one possible 15-minute snapshot.

With regard to the Wyoming tie, the TransWest line includes an approximately 700 + mile DC line crossing multiple states. Irrespective of the economic feasibility, regulatory, and permitting hurdles, the IPP market is not confident about when the line would be "in service" to California, never mind to Colorado, especially where that option has not been offered by the private proponent of that project. The economics of the PCW project depend on the TransWest line and not a line to Colorado, and wind generation in Wyoming is subject to a $1.00/MW tax.

Further, it is not appropriate to plan a transmission system expansion into Wyoming for the benefit of one IPP project. The high level of uncertainty about whether the PCW project would be built, even if TransWest is built, also raises the question whether Public Service could pursue development of alternative local generation and transmission as a Plan B if PCW fails. Even if the line and connected Wyoming generation were built as envisioned, the physical interconnection into Colorado grid and the power purchase contract structuring adding additional layers of complexity and uncertainty, requiring many additional considerations not addressed by Mr. Neil.

2. The 2017 Bids in the Public Service RFP Are Not a Sound Basis to Preliminarily Judge a Transmission Proposal.

Mr. Neil bases a criticism by finding that the proposed loop project would not provide efficient service to projects bid into the 2017 Public Service solicitation. From a market standpoint, Mr. Neil makes several errors in his assumptions. First, bids made in the 2017 Public Service RFP were optimized to connect the transmission system as it existed at that time, because new transmission was only treated as a cost in the bid evaluation process. Thus, the reason there are not many projects near the proposed loop is precisely because transmission options didn't exist. Second, the bid interconnection points referenced in many cases included long radial lines to project locations that are not reflected it Mr. Neil's analysis.

From a market policy perspective, it is not good policy in this transmission planning report to pre-suppose the outcome of a solicitation that is to occur in approximately one year, based on bids and pricing that existing nearly four years ago. RFP processes involve different modeling tools than transmission, and involve assumptions, market conditions, and evaluations that are not within the scope of transmission planning.

3. It is Not Appropriate to Continue to Rely on Long Radial Transmission Lines.

A third significant prong of Mr. Neil's analysis is his assumption that market participants could rely on "ERIS" transmission service as opposed to network service. This assumption is not correct. ERIS, or non-firm service, is an "interconnection product" under FERC law that a generator, at its discretion, may select. ERIS is not the same thing as a utility tool for managing a load and resource balance. The type of service procured by a generator is based on many factors, not the least of which includes project financing arrangements.

The current transmission system in Eastern Colorado is "full", from a legal perspective if not a technical perspective. Existing generators have binding interconnection contracts to inject power from their projects. From a technical perspective, long high voltage radial lines, especially in Eastern Colorado, are known to create transient stability issues. This is evident from the Rush Creek Task Force studies and the subsequent installment of Static Var compensators. Creating a network of lines alleviates this problem to a large extent. If Colorado joins a RTO/Market, a networked grid adds measurable benefits and options to market participants, both buyers and sellers of power.

B. Additional Comments of behalf of the Interwest Energy Alliance

Lisa Tormoen Hickey 719.302.2142 3225 Templeton Gap Road, Suite 217 P.O. Box 7920 Colorado Springs, CO 80907 Colorado Springs, CO 80933

February 22, 2021

Patrick Corrigan

80x30 Task Force

Re: Additional Comments on behalf of the Interwest Energy Alliance

The Interwest Energy Alliance participated in the 80x30 Task Force ("Task Force") and provided input on several occasions. The Task Force was formed out of the Colorado Coordinated Planning Group ("CCPG") to provide power flow studies with assumptions gathered from all participating utilities in Colorado, but was primarily led by Public Service Company of Colorado's ("PSCo's") need to prepare for the significant generation additions anticipated to serve its 2021 Electric Resource Plan and Clean Energy Plan ("PSCo ERP/CEP") requirements. New generation will require new injection capacity from various areas around the state, including areas which have been dormant related to potential generation development due to lack of infrastructure in prime renewable zones and inadequate capacity on the existing network. The sites cannot be fully developed and prepared to respond to requests for proposals ("RFPs") when there is no interconnection point which can accommodate new projects at reasonable cost. Therefore, the bid review modeling does not reflect the numerous projects with potential savings that are further back in the development process. Furthermore, reliability is enhanced if bids are developed from various areas of the state in each RFP, rather than requiring bids to be chosen from a cluster concentrated in a single area which has recently had transmission upgrades. This geographic and technical diversity reduces variability and uncertainty, with other grid support, and can help avoid numerous long radial lines. Coloradans would be better served by state-wide planning and less reliance on long gen-tie lines which can increase costs and reliability challenges and contribute to land use concerns and conflicts.

Interwest applauds the contributions of each utility into the Task Force discussions. The process was necessarily compressed as to time, but included careful review of a number of relevant scenarios. The 345 kV lines included in Alternative 3 and Alternative 7 appear to be required to serve PSCo's anticipated generation additions contemplated as part of the PSCo ERP/CEP. In addition, Interwest appreciates the added injection study proposal and results provided by Tri-State Generation and Transmission Association ("Tri-State") because its own additional needs should also be addressed in major transmission investments and transmission lines to be built in Colorado. The needs of the various utilities operating in Colorado through 2030 and thereafter, as well as scenarios reflecting opportunities for additional cost savings from increased regional flows are all relevant to the work of this Task Force, if not in this Phase I, in future Phases and studies to follow in the very near term. The lines planned and built out of these studies will last for decades. Thorough review of the transmission plan sufficiency at this stage is warranted, because stranded costs will result if 345 kV infrastructure is built with very large reactive support requirements, and 500 kV lines are ultimately required at some point in the future to serve minimum demand or market efficiency requirement.

Interwest generally supports the comments submitted by Dietze and Davis responding to the comments submitted on several occasions to the Task Force on behalf of the Office of Consumer Counsel ("OCC"). The OCC asserts that since the middle of the state has reflected numerous projects in the development stage in the last RFP, and that we should assume that these bids will still be available and should be the source of new projects for the PSCo ERP/CEP. However, the location of bids submitted in response to past RFPs was necessarily constrained by the transmission system as it existed at that time, rather than a system which reflected future potential. Colorado utilities have been aware of this "chicken and egg" issue for some years and should be acknowledged for their efforts to prevent the substantial lost opportunities from failure to plan and invest in new transmission lines required to tap into additional renewable resources around the state. As stated by PSCo, the time is now:

> The transmission system in Colorado is often designed and construction based on known generation additions to each providers system. Waiting to design and construct transmission in the wake of generation acquisition has resulted in numerous limitations to interconnecting new generation, especially beneficial energy resources located in energy rich areas such as Northeastern and Southern Colorado. To aid in resolving this chick and egg issue, the Colorado Coordinated Planning Group (CCPG) proposed the 80x30 Task Force in August 2020 to provide a forum for all stakeholders to collaboratively identify the transmission backbone infrastructure needed to enable the Colorado utilities meet the goals of Colorado's Clean Energy Plan. As noted in the 80x30 Task Force scope, this work is envisaged to be performed in two stages – this report provides the results and recommendations for Phase 1.

The OCC comments side-step the cost-saving benefits to be achieved by expanding the network transmission system in Colorado. The OCC ignores the need for planning past 2030 towards Colorado's 2040 and 2050 goals, and the need to serve all utilities operating in Colorado. The OCC also minimizes the steps to be taken before transmission can be planned and built through a regional market construct. Markets will take several years to become operational in Colorado, even after commitment to their cost savings are accepted and approved by Colorado utilities and decision-makers. In the interim, emissions reductions cannot be achieved on a cost-effective basis without substantial upgrades to the existing system, and expansion into previously-unserved areas.

Interwest does not believe that the final scenarios studied by the Task Force serves all of Colorado's transmission expansion needs over the next 10 years, much less the next 20 or 30 years. There are areas left without upgrades which leaves undeveloped low-cost wind and solar resources, including in the San Luis Valley and the Western Slope. Therefore, these questions should continue to be addressed in comprehensive planning discussions and through utility bilateral agreements. A number of important issues remain unresolved by this Task Force, including seams and upgrades to the existing system to make it work as efficiently as possible. The Rule 3627 review may help spur further coordination between utilities which is sorely needed in Colorado.

Very truly yours,
Lisa Tormoen Hickey
Attorney for the Interwest Energy Alliance

C. The Office of Consumer Counsel Statement on the 80x30TF Report

The Office of Consumer Counsel ("OCC") acknowledges the effort put forth by members of the Colorado Coordinated Planning Group ("CCPG"), and, in particular, the 80x30 Task Force ("80x30TF") in producing this report. The OCC recognizes that the role of the CCPG is high-level, coordinated transmission planning, as described in Section II of this report. And, appropriately, the

CCPG does not focus on project-specific planning efforts such as land acquisition, permitting, routing or even estimate costs.

In recent years, the leadership of the state of Colorado has developed polices for the utilities to replace fossil-based generation with clean energy amidst many other policy efforts. The CCPG has an important role in identifying options to achieve these policy goals. This 80x30TF report identifies just one possibility to interconnect renewable energy from the identified energy resource zones. But the OCC is concerned that the size and the scope of the alternatives presented are only part of the story - that there may be a better, more comprehensive solution that achieves the goals of SB19-236 and SB07-100, including integrating renewables and reliability in a manner that is just, reasonable and cost-effective – whether the comprehensive solution uses the existing system, ties to the Eastern Interconnection, utilizes another out-of-state option or includes other in-state options. This cannot be determined if we focus on Public Service's proposed alternatives before we look at the bigger picture. The comments below address several areas that should be considered before committing to transmission facilities that may not be necessary at this time and, as such, may not be the best solution for ratepayers or the people of Colorado. Note that these comments are written based on the latest draft report as the final draft of the report, containing revisions in line with discussions at the February 18 task force meeting, is not available as of the time of filing these comments.

A. Scope and Objectives

At the initial 80x30TF meeting, Public Service brought forth its objectives and alternatives. The objectives were revised and agreed to by the task force and are stated in *Section III, Scope, Purpose and Objectives*. This section goes on to further refine the goals, focusing on SB07-100. These refinements help clarify the scope, but the study scope did not, and should not, focus entirely on SB07-100. The OCC is not opposed to expanding the transmission system in order to accommodate renewable resources. However, high-level planning should be an open process to provide options and evaluate the impacts of varying possibilities, not predetermined positions.

B. Reference Baseline

The first problem is that Public Service, which developed the alternatives and completed the planning studies for each alternative, did not provide a baseline study that evaluated whether the additional capacity could be accommodated on the existing transmission system, with specific system improvements. That is, this report referenced projected generation needs for the upcoming Clean Energy Plan, but it did not set a baseline "do-nothing" alternative which would site new generation near existing injection capabilities and upgrade the system accordingly, as is the typical process for transmission planning. Rather, the generation in the provided "benchmark" case would be sited exclusively at the eastern outskirts of the existing system. Because there were sufficient bids in the 2016 ERP proposing to connect to the existing system and meet the expected needs of the upcoming Clean Energy Plan, the OCC requested that the 80x30TF look at the possibility of this true "do-nothing" alternative, but it was not presented to the 80x30TF. A massive transmission expansion such as that proposed in this report should be approached with caution, to ensure the projects are necessary and that they provide the reliability needed for a secure system without overbuilding.

C. The Chicken and the Egg

The OCC is aware that Public Service is set to propose its Clean Energy Plan, and states that this transmission expansion is needed in advance of the Clean Energy Plan. However, as this report states, this is a chicken and egg situation – which comes first. This proposed transmission loop may help the Clean Energy Plan – by providing transmission access. But if this proposed transmission loop precedes the Clean Energy Plan, it is quite possible to be overbuilt at a significant cost to ratepayers. As such, it is premature to study the transmission plan in advance of the ERP. Any decision regarding investment in transmission expansion must be made in conjunction with the ERP.

D. Potential for Bias

The OCC is concerned with the potential for bias in this report. We have been told in many proceedings that transmission planning is not a simple, quick analysis. However, the entire process for this report from the initial scoping meeting to the draft report spanned only about three months. Although the task force consisted of members from many different entities, the scope, the alternatives and the studies included in this Phase I effort were all controlled by Public Service. While this may not be in and of itself a problem, it is important to be aware that when the inputs are primarily controlled by one entity, the results may be biased to meet the needs or desires of that entity. Here, Public Service must meet the needs of the Clean Energy Plan required by statute and this bias may preclude identification of opportunities and synergies with the existing system or even other entities, ultimately at the expense of ratepayers. This is of particular importance as coal generation is retired statewide in light of a carbon-free future. One example of this potential for bias is that Public Service identified networking Cheyenne Ridge gen-tie as an objective at the initial meeting. Although this was removed as an objective in that meeting, it was included in all alternatives. The OCC is not making a technical evaluation of this concept, but decision-makers using this report need to ensure that networking of the gen-tie would provide added reliability and significant operational improvements, considering the massive costs for the selected alternative. Without an alternative omitting the networking of this gen-tie, there can be no way to determine this.

E. Cost Estimates

It is important to note that, with an estimated cost of $2.4 billion, these estimates are based on a rule-of-thumb and are not inclusive of all upgrades necessary to get the energy to the loads. There are several areas where costs would likely change, most often as adders. First, this cost estimate is just a number with no justification – this report clearly states the source of the estimates is on a $/mile basis from MISO. Appropriate for this point in time in the process, the estimate is just an indicative estimate – it has no basis in actual estimating methods. It is a guess based on a rule-of-thumb and could turn out to be significantly different – either higher or lower. Second, although the alternatives appear to reduce the number of overloads that could result when moving the renewable energy into the Denver Metro area, they are only compared to the benchmark analysis. There is not an identification of the overloads in the true baseline situation described above. These overloads are shown in Table 3 in Section H of the report and will be an additional cost on top of the estimate provided in this report. The cost of resolving any such Denver Metro overloads could run to the hundreds of millions of dollars. Further, Public Service has not demonstrated that it can fully resolve the Denver Metro overloads, which would be necessary to get the energy from the energy resource zones to the Denver Metro load center. Third, as this system is primarily used for getting renewable energy out of the renewable energy zones, there will likely be a need for a significant amount of reactive power. These needs are not known, as the generation mix and locations are not known. However, the costs to meet these reactive power needs may be significant and would be in addition to the $2.4 billion. Fourth, the costs to upgrade existing stations were considered to be negligible compared to $2.4 billion. This may be true, but if there are multiple upgrades requiring additional land and reconfiguration, the costs could add up to be a noticeable increase in costs.

F. Amount of Renewable Capacity

The Report is not clear regarding the amount of renewable capacity that this transmission system is trying to accommodate. Earlier work reflected that Public Service's resource planning group stated that 2,800 MW of wind and 2,100 MW of solar for a total of 4,900 MW was needed to meet the emissions reduction goal. At some point, this was reduced to 2,160 MW of new wind with the possible replacement of 640 MW of existing wind whose contracts expire. This report discusses 3,000 MW of renewables, but does not explain where this number came from and its relationship to the earlier values of 4,900 MW from Public Service's resource planning group. And this change did not appear to impact the alternatives.

G. Conclusion

The OCC is concerned with the impact of this large plan on ratepayers – which is in addition to the ordinary transmission activities, such as additions and upgrades to meet load growth. The OCC believes it is essential to have a full picture of issues, opportunities and related costs in order to make informed decisions. Recognizing this is a high-level project plan, this report is still lacking some analyses to make this a complete transmission study. As such, it is important to give this report appropriate weight when referencing this in litigated proceedings.

D. RES Stakeholder Comment for 80x30 Phase 1 Report

RES appreciates the opportunity to comment on the 80x30 Task Force Phase I Transmission Report. The goals of this study include evaluating the buildout of transmission with a goal of injecting geographically diverse sources of renewable energy to replace existing fossil fuel generation in order to meet the 80x30 carbon reduction goals. As a renewable energy developer headquartered in Colorado, RES appreciates the opportunity to lend our perspective on this study.

RES agrees with the findings regarding the need for additional transmission, and believes there are a number of benefits to the Alternative 3 transmission plan for renewable developers and the future integration of renewable energy on the Xcel transmission system that are not mentioned in the study which we would like to bring to the Planning Group's attention.

1) By crossing a number of landowners with the Cheyenne Ridge – Lamar stretch, this project would create competitive downward price pressure for renewable projects. When there is more land to choose from, competition will help keep land prices reasonable.
2) By tying in areas with high wind (Cheyenne) to areas with high solar (Tundra – Lamar), the transmission project utilization will be increased due to the occasionally complementary nature of the two resources.
3) By linking two high renewable resource areas the additional transmission creates more short circuit stability. One recommendation for additional analysis would be to compare the N-1 Weighted Short Circuit Ratio or dynamic analysis in order to assess the grid strength of the options. It would be unfortunate if dynamic stability later limited the amount of renewable generation below the thermal limits.
4) By tying Cheyenne Ridge to Lamar the project gives advantages to future development. Since the 80x30 goals are only an incremental goal, the future value of the transmission alternatives should be considered. Some helpful attributes Alternative 3 has to future transmission development:
    a. The ability to direct flows along the loop with a FACTS device.
    b. More fully integrating solar and wind resources to a location friendly to export, Lamar.

c. More fully integrating load centers to a location friendly to import, Lamar.

5) RES has not experienced an occasion where transmission was overbuilt to integrate future renewable generation. In our experience, what seem like ambitious transmission projects for renewable generation quickly appear inadequate to meet all the potential generation development.

RES believes that if these benefits are included in the analysis, *and with additional grid strength analysis added to the study*, Alternative 3 will become the clear option for meeting the 80x30 goal and further GHG reduction plans.

Blake King
Transmission Analyst

C 858-740-1474
blake.king@res-group.com | http://www.res-group.com

80x30 Task Force Meeting #12

September 15, 2021

Balanced Portfolios New Generation Locations

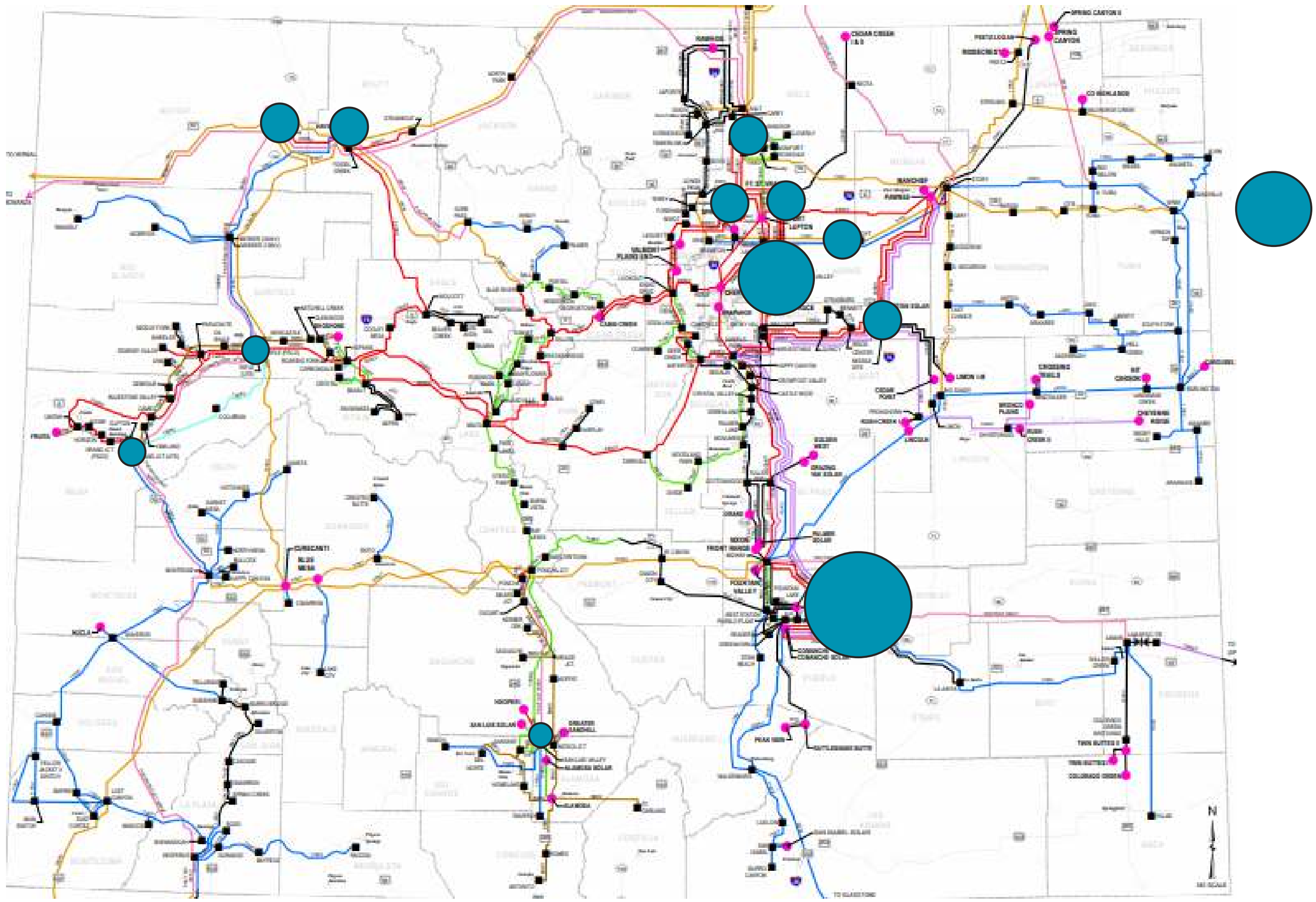
Xcel Energy

		P 1	P 2	P 3	P 4	Reference
Northern Area	Husky	200	200	0	0	Stand-alone
	Keenesburg	250	250	0	0	Stand-alone
	Ft St Vrain	250	250	0	0	Stand-alone
	Pawn-FtLup	250	250	250	0	DISIS GI-2020-15
Central Area	Missile Site	200	0	0	0	Stand-alone
	Pawnee	500	0	0	0	Stand-alone
	Pawn-Missile	0	0	199	199	DISIS GI-2020-6
	Sidney-Pawn	0	0	0	600	SPP North
	Barr Lake	0	0	199	199	DISIS GI-2020-16
	Green Valley	500	500	0	0	Stand-alone
San Luis Valley Area	San Luis Valley	60	60	0	0	Stand-alone
Southern Area	Mirasol	1230	1230	1299	299	DISIS GI-2020-1, -4, -7, -10
	Boone-Coman	200	200	199	199	DISIS GI-2020-3
	Boone-Midway	0	0	374	374	DISIS GI-2020-13
	Comanche	300	300	0	0	Stand-alone
	Coman-Midway	0	0	230	230	DISIS GI-2020-10
	Lamar-Tundra	0	0	0	600	SPP South
	Mid-Waterton	0	1100	1100	1100	DISIS GI-2020-12, -14
West Slope	Craig	600	600	200	0	Stand-alone
	Hayden	200	200	200	0	Stand-alone
	Rifle	100	100	100	0	Stand-alone
	Grand Jct	100	100	100	375	Stand-alone
	Total	**4940**	**5340**	**4450**	**4175**	

Balanced Proposal 1

Best performing
- More north, less south

All four portfolios have similar metro dispatch



Balanced Portfolio Results

Overloaded Facility	Region	Contingency	New overloaded transmission facilities 80x30TF CN-1	80x30TF CN-2	80x30TF CN-3	80x30TF CN-4
Greenwood-Monaco 230	Metro	Buckley2-Smoky Hill 230		109%	119%	119%
Monaco-Sullivan 230	Metro	Buckley-Smoky Hill 230		108%	120%	119%
Buckley-Tollgate 230	Metro	Greenwood-Monaco 230		100%	103%	105%
Buckley-Smoky Hill 230	Metro	Greenwood-Monaco 230				100%
Leetsdale-Harrison 115	Metro	Leetsdale-Monroe 230 kV		102%	110%	109%
Daniels Park-Prairie #1 230	Metro	Daniels Park-Prairie #2 230		105%	125%	121%
Daniels Park-Prairie #2 230	Metro	Daniels Park-Prairie #1 230		103%	124%	120%
Greenwood-Prairie # 1 230	Metro	Daniels Park-Prairie #1 230 kV			112%	107%
Greenwood-Prairie #2 230	Metro	Daniels Park-Prairie #2 230 kV			115%	110%
Havana1-Chambers 115	Metro	Havana2-Chambers 115	127%	126%	112%	114%
WL_Child-Archer 230	Metro	Ault-LRS 345				115%
Deer Creek-Soda Lake 115	Metro	Chatfield-Waterton 230		107%	112%	109%
Godfreytp-Greeley 115	Metro	Ft.Lupton 230/115	106%	101%		102%
FV-MidwayBR 115	South	MidwayBR-RD_Nixon 230			104%	
MidwayPS-MidwayBR 230	South	MidwayPS-Fuller 230		120%	123%	102%
Daniels Park-Fuller 230	South	MidwayPS-Waterton 345		115%		
Boone-MidwayPS 230	South	70120-70122			108%	109%
D.Pk-MidwayWatTP	South	70466-70814			101%	

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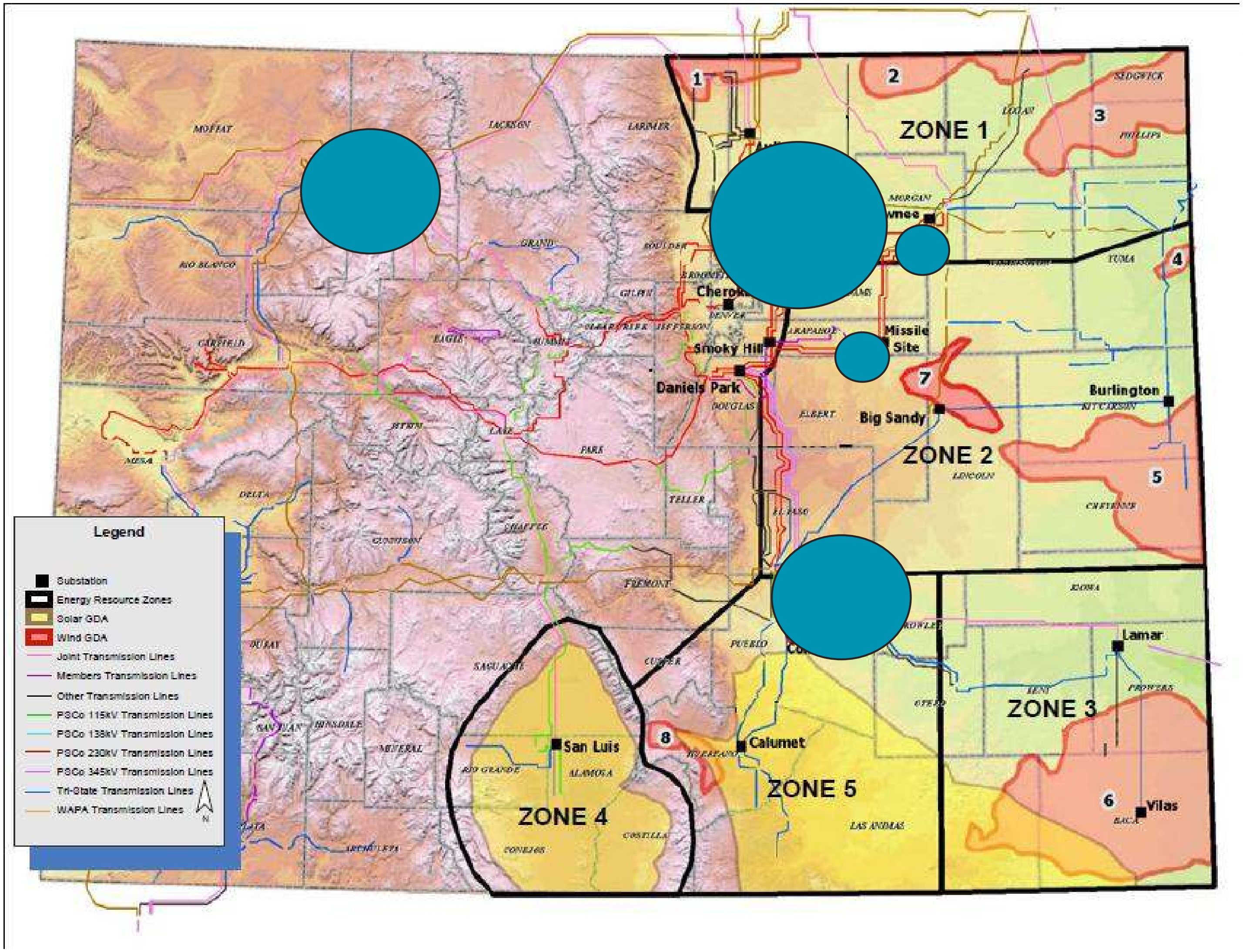
PSCo Sensitivity Portfolios

- S1 – Balanced – 4600 MW
- S2 – North focused – 4900 MW
- S3 – South focused – 4900 MW

		S 1	S 2	S 3
Northern Area	Husky	200	200	200
	Keenesburg	300	400	200
	Ft St Vrain	500	400	200
	Pawn-FtLup	300	400	200
Central Area	Missile Site	200	200	200
	Pawnee	200	200	200
	Pawn-Missile	0	0	0
	Sidney-Pawn	0	0	0
	Barr Lake	0	0	0
	Green Valley	500	300	300
	Spruce	500	300	300
San Luis Valley Area	San Luis Valley	0	0	0
Southern Area	Mirasol	500	1000	1100
	Boone-Coman	200	200	500
	Boone-Midway	0	0	0
	Comanche	200	300	500
	Coman-Midway	0	0	0
	Lamar-Tundra	0	0	0
	Mid-Waterton	0	0	0
West Slope	Craig	300	300	300
	Hayden	300	300	300
	Rifle	200	200	200
	Grand Jct	200	200	200
	Total	**4600**	**4900**	**4900**

Portfolio Focus Areas

Xcel Energy®



Sensitivity Portfolio Results

Overloaded Facility	Region	Contingency	New overloaded transmission facilities		
			80x30TF S-1	80x30TF S-2	80x30TF S-3
Havana1-Chambers 115	Metro	N-0	104%	104%	104%
Greenwood-Monaco 230	Metro	Buckley2-Smoky Hill 230		102%	110%
Monaco-Sullivan 230	Metro	Buckley-Smoky Hill 230		101%	110%
Buckley-Tollgate 230	Metro	Greenwood-Monaco 230			103%
Leetsdale-Harrison 115	Metro	Leetsdale-Monroe 230 kV			103%
Daniels Park-Prairie #1 230	Metro	Daniels Park-Prairie #2 230			101%
Havana1-Chambers 115	Metro	Havana2-Chambers 115	129%	123%	123%
Godfreytp-Greeley 115	Metro	Ft.Lupton 230/115	111%	108%	105%
FV-MidwayBR 115	South	MidwayBR-RD_Nixon 230			109%

All Results

Overloaded Facility	Region	Contingency	New overloaded transmission facilities						
			80x30TF P-1	80x30TF P-2	80x30TF P-3	80x30TF P-4	80x30TF S-1	80x30TF S-2	80x30TF S-3
Havana1-Chambers 115	Metro	N-0				104%	104%	104%	104%
Greenwood-Monaco 230	Metro	Buckley2-Smoky Hill 230		109%	119%	119%		102%	110%
Monaco-Sullivan 230	Metro	Buckley-Smoky Hill 230		108%	120%	119%		101%	110%
Buckley-Tollgate 230	Metro	Greenwood-Monaco 230		100%	103%	105%			103%
Buckley-Smoky Hill 230	Metro	Greenwood-Monaco 230				100%			
Leetsdale-Harrison 115	Metro	Leetsdale-Monroe 230 kV		102%	110%	109%			103%
Daniels Park-Prairie #1 230	Metro	Daniels Park-Prairie #2 230		105%	125%	121%			101%
Daniels Park-Prairie #2 230	Metro	Daniels Park-Prairie #1 230		103%	124%	120%			
Greenwood-Prairie # 1 230	Metro	Daniels Park-Prairie #1 230 kV			112%	107%			
Greenwood-Prairie #2 230	Metro	Daniels Park-Prairie #2 230 kV			115%	110%			
Havana1-Chambers 115	Metro	Havana2-Chambers 115	127%	126%	112%	114%	129%	123%	123%
WL_Child-Archer 230	Metro	Ault-LRS 345				115%			
Deer Creek-Soda Lake 115	Metro	Chatfield-Waterton 230		107%	112%	109%			
Godfreytp-Greeley 115	Metro	Ft.Lupton 230/115	106%	101%		102%	111%	108%	105%
FV-MidwayBR 115	South	MidwayBR-RD_Nixon 230			104%				109%
MidwayPS-MidwayBR 230	South	MidwayPS-Fuller 230		120%	123%	102%			
Daniels Park-Fuller 230	South	MidwayPS-Waterton 345		115%					
Boone-MidwayPS 230	South	70120-70122			108%	109%			
D.Pk-MidwayWatTP	South	70466-70814			101%				

Key Results & Observations

- Metro Area overloads remain, though less with more northern dispatch
- Long gen-ties required to get to some ERZs and GDAs
- Many locations have not been requested by developers
  - Fort St Vrain
  - Spruce
  - Husky
  - Rifle
  - Grand Junction

Next Steps

- What's next?
- Continue monthly meetings?
  - If so, Thursday October 21

Questions / Comments

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