Appendix P

2024 Rule 3627 Ten-Year Transmission Plan

Public Service Company of Colorado

Supporting Documentation

Table of Contents

2024-2034 Public Service Generation Resources Table

Public Service Company of Colorado Generation Resources 2024-2034

Generator Name	Generation Type	Own/ Purchase	Summer Accredited Capacity (MW)										
			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Comanche 2	Coal	Own	335.0	335.0									
Comanche 3	Coal	Own	500.0	500.0	500.0	500.0	500.0	500.0	500.0				
Craig 1	Coal	Own	41.6	41.6									
Craig 2	Coal	Own	40.0	40.0	40.0	40.0	40.0						
Hayden 1	Coal	Own	135.1	135.1	135.1	135.1	135.1						
Hayden 2	Coal	Own	98.3	98.3	98.3	98.3							
Pawnee 1	Coal	Own	505.0	505.0									
Cherokee 4	Gas Steam	Own	310.0	310.0	310.0	310.0							
Pawnee	Gas Steam	Own			505.0	505.0	505.0	505.0	505.0	505.0	505.0	505.0	505.0
Cherokee 5,6,7	Gas CC	Own	576.0	576.0	576.0	576.0	576.0	576.0	576.0	576.0	576.0	576.0	576.0
Ft. St. Vrain 1,2,3,4	Gas CC	Own	740.0	740.0	740.0	740.0	740.0	740.0	740.0	740.0	740.0	740.0	740.0
Rocky Mt Energy Center 1,2,3	Gas CC	Own	594.0	594.0	594.0	594.0	594.0	594.0	594.0	594.0	594.0	594.0	594.0
Brush 4D	Gas CC	Purchase	130.7	130.7	130.7								
Arapahoe 5,6,7	Gas CC	Purchase	117.6	117.6									
Alamosa 1	Gas CT	Own	12.8	12.8	12.8								
Alamosa 2	Gas CT	Own	13.5	13.5	13.5								
Blue Spruce 1	Gas CT	Own	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0
Blue Spruce 2	Gas CT	Own	134.0	134.0	134.0	134.0	134.0	134.0	134.0	134.0	134.0	134.0	134.0
Fruita 1	Gas CT	Own	14.0	14.0	14.0								
Ft. Lupton 1	Gas CT	Own	44.0	44.0	44.0								
Ft. Lupton 2	Gas CT	Own	44.0	44.0	44.0								
Ft. St. Vrain 5	Gas CT	Own	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Ft. St. Vrain 6	Gas CT	Own	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Valmont 6	Gas CT	Own	43.0	43.0	43.0								
Brush 1	Gas CC	Purchase	50.5	50.5									
Brush 2	Gas CC	Purchase	68.4	68.4									
Brush 3	Gas CT	Purchase	25.2	25.2									
Fountain Valley 1-6	Gas CT	Purchase	236.4	236.4	236.4	236.4	236.4	236.4	236.4	236.4			
Plains End I	Gas CT	Purchase	111.8	111.8	111.8	111.8							
Plains End II	Gas CT	Purchase	107.5	107.5	107.5	107.5							
Spindle Hill 1 + 2	Gas CT	Purchase	271.7	271.7	271.7								
Cabin Creek A	Storage	Own	137.7	137.7	137.7	137.7	137.7	137.7	137.7	137.7	137.7	137.7	137.7
Cabin Creek B	Storage	Own	137.7	137.7	137.7	137.7	137.7	137.7	137.7	137.7	137.7	137.7	137.7
Waste Management	Biomass	Purchase	3.3										
Ames	Hydro	Own	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Salida 2	Hydro	Own	0.3	0.3	0.3	0.3							
Shoshone A	Hydro	Own	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Shoshone B	Hydro	Own	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Tacoma 1	Hydro	Own	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Tacoma 2	Hydro	Own	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
City of Boulder - Betasso	Hydro	Purchase	1.7	1.7	1.7	1.7							
City of Boulder - Silver Lake	Hydro	Purchase	1.7	1.7	1.7	1.7							
City of Boulder - Lakewood	Hydro	Purchase	1.7	1.7	1.7	1.7							
DWB - Foothills	Hydro	Purchase	1.3	1.3	1.3								
DWB - Strontia	Hydro	Purchase	0.7	0.7	0.7								
DWB - Dillon	Hydro	Purchase	1.1	1.1	1.1								
DWB - Roberts Tunnel	Hydro	Purchase	3.4	3.4	3.4								
DWB - Hillcrest	Hydro	Purchase	1.3	1.3	1.3								
DWB - Gross Reservoir	Hydro	Purchase	4.5	4.5	4.5	4.5							
Redlands Water & Power	Hydro	Purchase	0.8										
Pena Station	Solar	Own	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
SunE Alamosa I	Solar	Purchase	3.1	3.1	3.0	3.0							
Greater Sandhill	Solar	Purchase	7.4	7.4	7.3	7.3	7.3	7.2	7.2				
San Luis	Solar	Purchase	13.8	13.7	13.7	13.6	13.5	13.5	13.4	13.3			
Hooper	Solar	Purchase	23.1	23.0	22.9	22.8	22.7	22.6	22.4	22.3	22.2	22.1	22.0
Comanche	Solar	Purchase	55.5	55.2	54.9	54.7	54.4	54.1	53.9	53.6	53.3	53.1	52.8
DG - BTM Solar	DG Solar	Purchase	155.4	171.6	185.0	196.5	208.4	220.6	230.9	239.7	248.7	257.5	266.1
DG - Community Solar	DG Solar	Purchase	87.4	112.0	122.4	148.2	192.6	192.9	205.7	218.0	229.8	241.1	251.4
Titan	Solar	Purchase	23.4	23.2	23.1	23.0	22.9	22.8	22.7	22.6	22.4	22.3	22.2
Rush Creek I	Wind	Own	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6
Rush Creek II	Wind	Own	26.8	26.8	26.8	26.8	26.8	26.8	26.8	26.8	26.8	26.8	26.8
Spring Canyon	Wind	Purchase	8.0	8.0									

Public Service Company of Colorado Generation Resources 2024-2034

Generator Name	Generation Type	Own/ Purchase	Summer Accredited Capacity (MW)										
			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Twin Buttes	Wind	Purchase	10.1	10.1	10.1								
Cedar Creek	Wind	Purchase	40.3	40.3	40.3	40.3							
Peetz Table	Wind	Purchase	26.7	26.7	26.7	26.7	26.7	26.7	26.7	26.7	26.7		
Logan	Wind	Purchase	26.9	26.9	26.9	26.9							
Northern Colorado I	Wind	Purchase	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Northern Colorado II	Wind	Purchase	3.0	3.0	3.0	3.0	3.0	3.0					
Cedar Creek II	Wind	Purchase	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3
Cedar Point	Wind	Purchase	33.8	33.8	33.8	33.8	33.8	33.8	33.8	33.8			
Limon I	Wind	Purchase	26.8	26.8	26.8	26.8	26.8	26.8	26.8	26.8	26.8	26.8	26.8
Limon II	Wind	Purchase	26.8	26.8	26.8	26.8	26.8	26.8	26.8	26.8	26.8	26.8	26.8
Limon III	Wind	Purchase	26.9	26.9	26.9	26.9	26.9	26.9	26.9	26.9	26.9	26.9	26.9
Golden West	Wind	Purchase	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4
Bighorn	Solar	Purchase	113.8	113.2	112.7	112.1	111.6	111.0	110.4	109.9	109.3	108.8	108.2
Colorado Green	Wind	Purchase	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.7
Mountain Breeze	Wind	Purchase	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
Cheyenne Ridge	Wind	Own	66.8	66.8	66.8	66.8	66.8	66.8	66.8	66.8	66.8	66.8	66.8
Bronco Plains	Wind	Purchase	40.1	40.1	40.1	40.1	40.1	40.1	40.1	40.1	40.1	40.1	40.1
Valmont 7	Gas CT	Own	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Valmont 8	Gas CT	Own	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Manchief 11 + 12	Gas CT	Own	262.0	262.0	262.0	262.0	262.0	262.0	262.0	262.0	262.0	262.0	262.0
Sun Mountain	Solar	Purchase	95.3	94.8	94.4	93.9	93.4	93.0	92.5	92.0	91.6	91.1	90.7
Neptune - Solar	Solar	Purchase	155.7	154.9	154.1	153.4	152.6	151.8	151.1	150.3	149.6	148.8	148.1
Neptune - Storage	Storage	Purchase	75.6	75.6	75.6	75.6	75.6	75.6	75.6	75.6	75.6	75.6	75.6
Thunder Wolf - Solar	Solar	Purchase	118.2	117.6	117.0	116.4	115.9	115.3	114.7	114.1	113.6	113.0	112.4
Thunder Wolf - Storage	Storage	Purchase	60.5	60.5	60.5	60.5	60.5	60.5	60.5	60.5	60.5	60.5	60.5

Public Service Reliability Criteria

Public Service Company of Colorado Reliability Criteria

This section cites the Public Service Company of Colorado System Performance Criteria for steady-state, transient stability and voltage stability simulations for planning events established in Table 1 of the NERC Standard TPL-001-5 and WECC Regional Criterion TPL-001-WECC-CRT-3.2.

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-3.2.

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-3.2.

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-3.2.

Voltage Stability Criteria

These are the same as specified in WR5 of WECC Regional Criterion TPL-001-WECC-CRT-3.2.

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-3.2.

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.

Public Service Facility Rating Methodology

Xcel Energy

Transmission

Facility Rating Methodology

Version 14.0

November 15, 2020

Table of Contents

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.

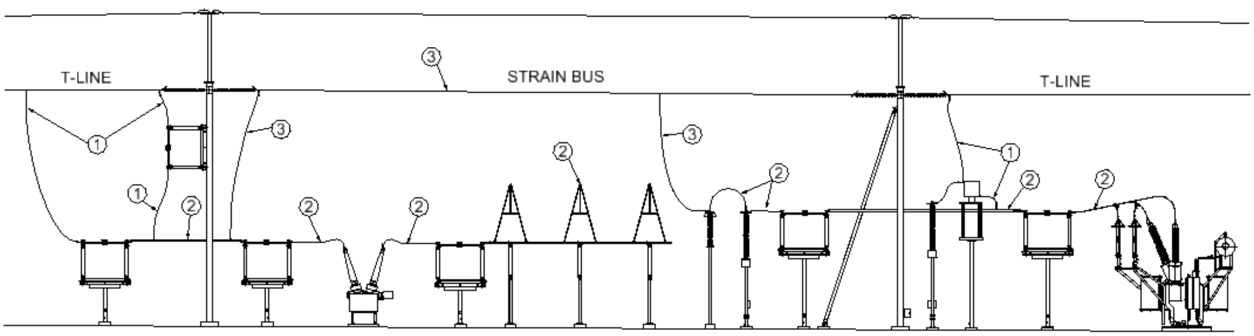
5.0 Transmission Substation Equipment Rating Methodology

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^{o}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.

Available Transfer Capability Implementation Document (ATCID)

1.0 PURPOSE

- This document serves to ensure that calculations are performed by PSCo in its roles as Transmission Service Provider and Transmission Operator 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.

- Total Transfer Capability (TTC) is defined in the NERC Glossary as:

  The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.

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
Brett Gruesner	Manager, Transmission Control Center (PSCo)
Eric Barry	Manager, Real Time Planning
Gilbert Flores	Manager, PSCo Transmission Planning

4.0 VERSION HISTORY

Date	Version Number	Change

Effective 04/01/2011	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
11/01/2017	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 Manager, Transmission Planning approver name. Updated Attachment 5 contact information. Added third bullet for authorization of NERC Waiver Letter use in Section 2.1.3.3.
04/27/2020	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
10/18/2021	8.0	Updated the list of approvers.
12/01/2022	8.1	Updated the list of approvers.
06/01/2023	8.2	Updated the list of approvers.
12/01/2023	9.0	Clarifications added to ATC Methodology and Attachment 1, section 3. Attachment 5 contacts updated. Expanded Counterflow description in Section 4.1.4.

Methodology

1. ATC Methodology

1.1. PSCo has selected the "Rated System Path Methodology" as described in NERC Reliability Standard MOD-029-2a to calculate TTC and ATC for ATC Paths.

1.2. PSCo also uses Transmission Reliability Margin (TRM) as described in NERC Reliability Standard MOD-008-1, and implemented per PSCo's Transmission Reliability Margin Implementation Document (TRMID).

1.3. PSCo does not use "Capacity Benefit Margin" (NERC Standard MOD-004-1), "Area Interchange Methodology" (NERC Standard MOD-028-2), or "Flowgate Methodology" (NERC Standard MOD-030-2).

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.

- 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 using 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, unless otherwise noted in PSCo's OASIS General Business Practices.

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, unless otherwise noted in PSCo's OASIS General Business Practices.

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:

303-273-4782

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.

3. The model shall use the WECC approved, and RMOSG (Rocky Mountain Operating Study Group) modified, heavy summer case for the upcoming year, and the bus subsystem of area 70 (PSCo BA Area), and 73 (WACM BA Area). Adjustments to the cases include, but are not limited to:

- PSCO's line ratings per the latest FAC-008-03.
- Facility status changes due to normal operations, planned facility outages, or known retirements.
- New facilities due to topology changes, or upcoming planned projects.
- Real Time Planning Group (RTP) shall coordinate these checks and adjustments with Transmission Planning (TP) and the Manager of the Transmission Control Center.
- The cutoff date for inclusion shall be the end of the relevant operating season for the year the study is performed.
- Please refer to the TTC Study Report for details of all adjustments to generation in the creation of each stressed case used to determine TTC for each ATC path.
- Cases used in this study shall be stored in the same location as the TTC Study Report and be easily retrievable.

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.

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: 11/01/2023	Brett Gruesner Manager, Transmission Control Center (PSCo) 18201 West 10th Ave. Golden, CO, 80401 Office: 303-273-4782 Brett.J.Gruesner@xcelenergy.com Nick Seitz Senior Engineer 18201 West 10th Ave. Golden, CO, 80401 Office: 303-273-4654 Nicholas.K.Seitz@xcelenergy.com	X		X	X	X		X
Southwestern Public Service Company Updated: 11/01/2023	Kyle McMenamin Manager, Transmission Control Center (SPS) Office: 806-640-6306 Kyle.McMenamin@xcelenergy.com		X	X	X	X		
Tri State Generation & Transmission Association Updated: 11/01/2023	Igor Kormaz Operations Support Manager Office: 303-254-3493 ikormaz@tristategt.org Ryan Hubbard Senior Manager Transmission Business Strategy Office: 303-254-3025 rhubbard@tristategt.org Kevin Cloud Senior OASIS/OATT Administrator Office: 303-254-3284 kcloud@tristategt.org Rocky Ray OASIS/OATT Administrator Office: 303-254-3017 rray@tristategt.org	X	X	X	X	X		

Platte River Power Authority Updated: 11/01/2023	Matt Thompson Operations Specialist and OASIS Administrator Office: (970) 229-1686 thompsonm@prpa.org Derek Book Operations Specialist Office: 970-229-5391 bookd@prpa.org Jeremy Brownrigg Transmission Planner brownriggj@prpa.org	X	X	X	X	X		X
Western Area Power Administration – Rocky Mountain Region AND Western Area Power Administration – Desert Southwest Region Updated: 11/01/2023	Jonathon W. Steward Transmission Business Unit Manager Western Area Power Administration/Rocky Mt. Region Office: 602-605-2774 Steward@WAPA.GOV Sean Erickson Transmission Policy Advisor Western Area Power Administration/Rocky Mt. Region Office: 970-461-7584 Erickson@WAPA.GOV Compliance Managers reliabiltycompliance@wapa.gov Steve Robinson Srobinson@WAPA.GOV		X	X	X	X		X
Public Service Company of New Mexico Updated: 11/01/2023	Aidan Gallegos Manager, System Operations Public Service Company of New Mexico Alvarado Square - MS EP11 Albuquerque, NM 87158 Office: 505 241-2191 Aidan.Gallegos@pnm.com Karen Reedy Transmission Planning Office: 505-241-4591 PNMTransPlanCompliance@pnmresources.com		X	X	X	X		X
Black Hills Colorado Electric Updated: 11/01/2023	Eric M. East Manager, Tariff and Contract Administration Office: 605-721-2261 Eric.East@blackhillscorp.com	X		X	X	X		
Colorado Springs Utilities Updated: 11/01/2023	Warren Rust Electric System Operations Superintendent Office: 719-668-4128 rrust@csu.org Jeff Hanson Transmission System Engineer Office: 719-668-8125 jhanson@csu.org		X	X	X	X		X

Intermountain Rural Electric Association Updated 11/01/2023	Pamela 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: 11/01/2023	CJ Brown Director, SPP Operations Office: 501-614-3569 cbrown@spp.org Derek Hawkins Manager, Reliability Office: 501-688-1662 dhawkins@spp.org OpsAFCEng@spp.org	X			X	X	X	X
California Independent System Operator Updated: 11/01/2023	Procedure Control Desk procctrldesk@caiso.com Ops Planning South Ops-Planning-South@caiso.com		X		X	X	X	X

Methodology Document	
Xcel Energy	Public Service Company of Colorado
M-004 Available Transfer Capability Implementation Document (ATCID)	**Version: 9.0**
File Name: PSC-PRO-PSCo M-004 Available Transfer Capability Implementation Document (ATCID)	**Page 20 of 22**

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.

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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

Capacity Benefit Margin Implementation Document (CBMID)

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

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

- Manager, Real Time Planning – 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, PSCo 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
Brett Gruesner	PSCo Control Center Manager
Eric Barry	Manager, Real Time Planning
Gilbert Flores	Manager, PSCo Transmission Planning

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
3/30/2016	3.0	Version 3 was never approved nor implemented.
1/20/2023	4.0	Updated approver list and approver job titles; Updated all information in the table on Attachment 1
12/1/2023	5.0	Updated approver list, and Attachment 1.

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:

303-273-4782

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 <u>AFTER</u> 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 8/11/2017)

Entity	email	Within PSCo	Neighbor	TOP	TSP	TP	RC	PC (PA)
Public Service Company of Colorado Updated: 11/01/2023	Brett Gruesner Manager, Transmission Control Center (PSCo) 18201 West 10th Ave. Golden, CO, 80401 Office: 303-273-4782 Brett.J.Gruesner@xcelenergy.com Nick Seitz Senior Engineer 18201 West 10th Ave. Golden, CO, 80401 Office: 303-273-4654 Nicholas.K.Seitz@xcelenergy.com	X		X	X	X		X
Southwestern Public Service Company Updated: 11/01/2023	Kyle McMenamin Manager, Transmission Control Center (SPS) Office: 806-640-6306 Kyle.McMenamin@xcelenergy.com		X	X	X	X		
Tri State Generation & Transmission Association Updated: 11/01/2023	Igor Kormaz Operations Support Manager Office: 303-254-3493 ikormaz@tristategt.org Ryan Hubbard Senior Manager Transmission Business Strategy Office: 303-254-3025 rhubbard@tristategt.org Kevin Cloud Senior OASIS/OATT Administrator Office: 303-254-3284 kcloud@tristategt.org Rocky Ray OASIS/OATT Administrator Office: 303-254-3017	X	X	X	X	X		

M-006 Capacity Benefit Margin Implementation Document (CBMID)

Version: 5.0

File Name: PSC-PRO-PSCo M-006 Capacity Benefit Margin Implementation Document (CBMID)

	rray@tristategt.org							
Platte River Power Authority Updated: 11/01/2023	Matt Thompson Operations Specialist and OASIS Administrator Office: (970) 229-1686 thompsonm@prpa.org Derek Book Operations Specialist Office: 970-229-5391 bookd@prpa.org Jeremy Brownrigg Transmission Planner brownriggj@prpa.org	X	X	X	X	X		X
Western Area Power Administration – Rocky Mountain Region AND Western Area Power Administration – Desert Southwest Region Updated: 11/01/2023	Jonathon W. Steward Transmission Business Unit Manager Western Area Power Administration/Rocky Mt. Region Office: 602-605-2774 Steward@WAPA.GOV Sean Erickson Transmission Policy Advisor Western Area Power Administration/Rocky Mt. Region Office: 970-461-7584 Erickson@WAPA.GOV Compliance Managers reliabiltycompliance@wapa.gov Steve Robinson Srobinson@WAPA.GOV		X	X	X	X		X
Public Service Company of New Mexico Updated: 11/01/2023	Aidan Gallegos Manager, System Operations Public Service Company of New Mexico Alvarado Square - MS EP11 Albuquerque, NM 87158 Office: 505 241-2191 Aidan.Gallegos@pnm.com Karen Reedy Transmission Planning Office: 505-241-4591 PNMTransPlanCompliance@pnmresources.com		X	X	X	X		X
Black Hills Colorado Electric Updated: 11/01/2023	Eric M. East Manager, Tariff and Contract Administration Office: 605-721-2261 Eric.East@blackhillscorp.com	X		X	X	X		
Colorado Springs Utilities Updated: 11/01/2023	Warren Rust Electric System Operations Superintendent Office: 719-668-4128 rrust@csu.org Jeff Hanson Transmission System Engineer Office: 719-668-8125 jhanson@csu.org		X	X	X	X		X

Intermountain Rural Electric Association Updated 11/01/2023	Pamela 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: 11/01/2023	CJ Brown Director, SPP Operations Office: 501-614-3569 cbrown@spp.org Derek Hawkins Manager, Reliability Office: 501-688-1662 dhawkins@spp.org OpsAFCEng@spp.org	X			X	X	X	X
California Independent System Operator Updated: 11/01/2023	Procedure Control Desk procctrldesk@caiso.com Ops Planning South Ops-Planning-South@caiso.com		X		X	X	X	X

Transmission Reliability Margin Implementation Document (TRMID)

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
Brett Gruesner	Interim PSCo Control Center Manager
Eric Barry	Manager, Real Time Planning Engineering
Gilbert Flores	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

11/22/2022	5.0	Updated list of approvers
06/01/2023	6.0	Updated list of approvers

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 to the Manager, Transmission Control Center at the address or phone number listed below.

Phone Number:

303-273-4782

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.

Public Service Planning Authority SOL Methodology

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.
12/16/2014	2.0	1.0	The revision includes the addition of a procedure for releasing a revised SOL

[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 Weld PS-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.

			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.
- 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

[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.

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 Contingency" may limit the TOT7 Total Transfer Capability. This multiple contingency is <u>not</u> 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).
-

[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.

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.

<u>**Transient Stability Studies – System Response to Disturbances**</u>

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.

Voltage Stability Studies - Definition

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.

Voltage Stability Studies - Criteria

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.

Voltage Stability Studies - Study Cases

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

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

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.

<u>Voltage Stability Studies - V-Q Analysis (for Reactive Power Studies)</u>

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 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.

Voltage Stability Studies - P-V Analysis (for Real Power Studies)

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.