Big Sandy-Landsman Creek 230 kV TTC
And
Landsman Creek-Burlington 230 kV TTC

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Background

The Big Sandy-Landsman Creek 230 kV (breaker to breaker) and the Landsman Creek-Burlington 230 kV (breaker to breaker) lines are used to schedule power bi-directionally between Big Sandy and Landsman Creek; and between Landsman Creek and Burlington, respectively. Table 1 shows the parameters of each line. Figure 1 shows the lines' location in eastern Colorado.

Table 1: Transmission Line Parameters

Description	Conductor (ACSR)	Normal Rating (MVA)	Emerg. Rating (MVA)	Length (Miles)	Design Temperature (^{o}C)	Limited Element
Big Sandy-Landsman Creek 230 kV	954	275.0	291.5	75.5	50	Conductor
Landsman Creek-Burlington 230 kV	954	275.0	291.5	5.0	50	Conductor

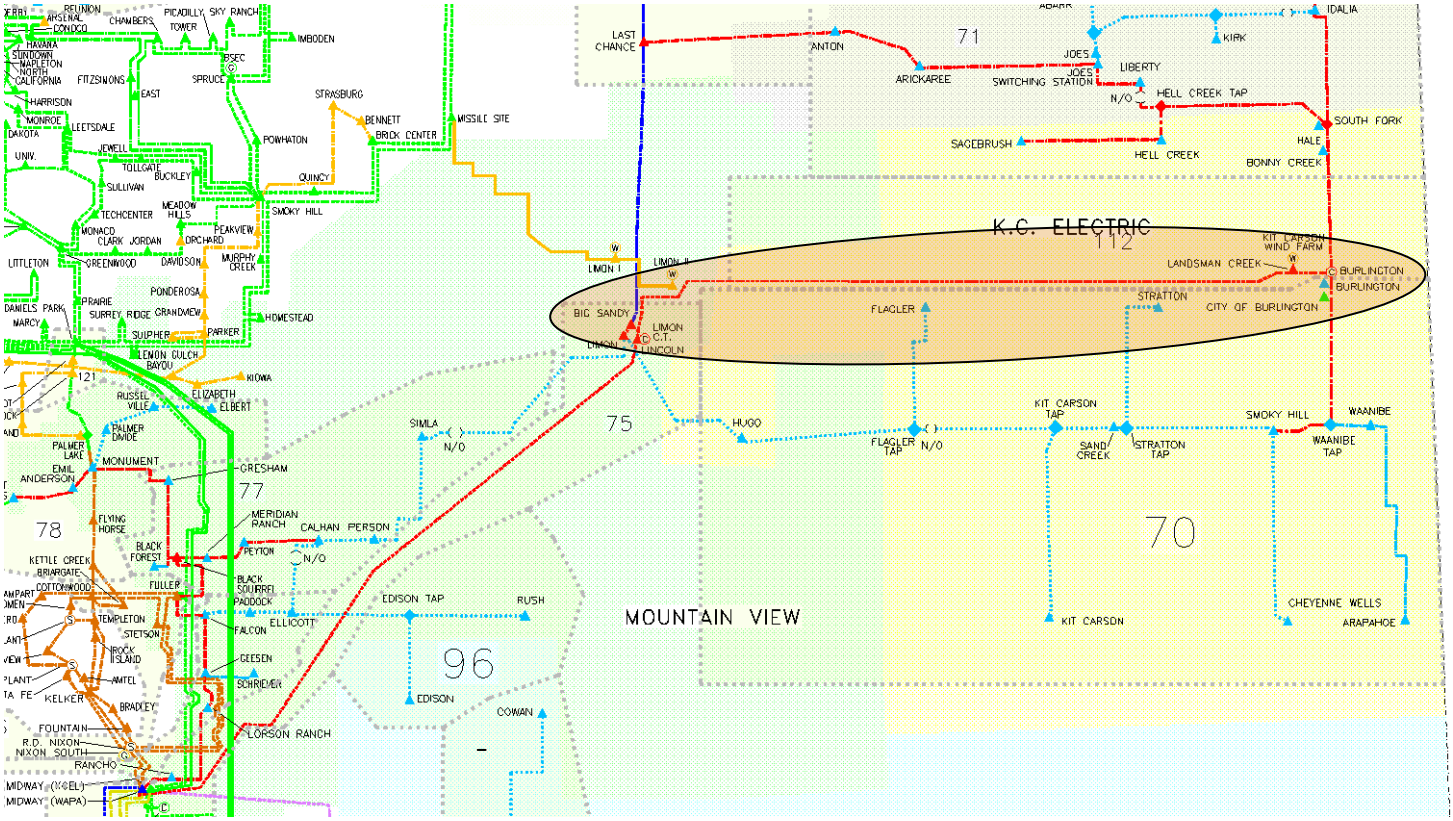


Figure 1: Eastern Colorado Transmission System

Objective

The objective is to conduct power flow and transient stability studies to determine the Total Transfer Capability (TTC) of the Big Sandy-Landsman Creek 230 kV and the Landsman Creek-Burlington 230 kV lines in accordance with Standard MOD-029-1a — Rated System Path Methodology (Appendix B).

Base Case Assumptions

The 2013HS (heavy summer) and 2013LA (light autumn) LGIP PSSE base cases were selected to perform the power flow study. An equivalent 2013HS LGIP PSLF case will be used to perform the transient stability study. These two base cases are updated with the latest branch and generator ratings in the study area. They consist of the following modeling parameters, as described in Requirement 1 (R1) of Standard MOD-029-1a.

- all WECC base case elements such as transmission lines, transformers, shunt capacitors, etc.,
- latest load and generation forecast,
- existing and planned Special Protection System (SPS), if any, and
- latest facility ratings.

Methodology

TTC is defined as the amount of electric power that can be transferred reliably from one area to another area of the interconnected transmission system by utilizing all available transmission lines between these areas under stressed system operating conditions. In this particular study, the available transmission lines are the Big Sandy-Landsman Creek 230 kV and the Landsman Creek-Burlington 230 kV lines. The stressed system operating conditions include various generation dispatches for heavy summer and light autumn loads of 2013.

Requirement 2 (R2) of Standard MOD-029-1a describes the methodology as follow:

- 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 Available Transfer Capability (ATC) Path while at the same time satisfying all planning criteria

- Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependent on a Special Protection System (SPS), 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.

- For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit.

- For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

- The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this 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 R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.

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

- 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.

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

- Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path.

- Within seven calendar days of the finalization of the study report, the Transmission Operator 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.

The power flow study is performed in accordance with Tri-State's planning criteria (Appendix A). They are consistent with the planning criteria of Western Electricity Coordinating Council (WECC) and North American Electric Reliability Council (NERC).

Power flow Study Results

This TTC study includes power flow in both directions for the Big Sandy-Landsman Creek 230 kV and the Landsman Creek-Burlington 230 kV lines.

West-to-East Flow:

Two study cases, **13HS1a** and **13LA1a**, derived from the base cases, **13HS0** and **13LA0**, are used to study the West-to-East flows on the Big Sandy-Landsman Creek 230 kV line. Another two study cases, **13HS2a** and **13LA2a**, also derived from the base cases, **13HS0** and **13LA0**, are used to study the West-to-East flows on the Landsman Creek-Burlington 230 kV line. The respective stressed generation for the four study cases, including Lincoln (also known as Limon) and Burlington unit generation; and other generation in southeastern Colorado and Montana/Idaho areas, are shown in Table 2. Red numbers under the study cases indicate the generation that are different from the base cases.

Table 2: Stressed Generation Dispatches for Various Study Cases
(West-to-East Flow)

Number	Name	Pmax	Pmin	Base Case 13HS0	Study Case 13HS1a	Study Case 13HS2a	Base Case 13LA0	Study Case 13LA1a	Study Case 13LA2a
		(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
Area 62 & 60	Montana & Idaho Generation	8823.1 HS 8823.1 LA	1062.4 HS 1062.4 LA	7617.8	7520.4	7469.4	7616.7	7339.2	7288.2
73181 (Z756)	SIDNEYDC 230	200.0	-200.0	200.0	-200.0	-200.0	200.0	-200.0	-200.0
73302 (Z752)	BRLNGTN1 13.8	50.0	25.0	29.0	0.0	0.0	0.0	0.0	0.0
73303 (Z752)	BRLNGTN2 13.8	50.0	25.0	29.0	0.0	0.0	0.0	0.0	0.0
72714 (Z751)	KIT.CARSON 0.69	51.0	2.4	51.0	0.0	51.0	51.0	0.0	51.0
73532 (Z752)	LINCOLN1 13.8	68.0	40.0	0.0	68.0	68.0	0.0	68.0	68.0
73533 (Z752)	LINCOLN2 13.8	68.0	40.0	59.0	68.0	68.0	0.0	68.0	68.0
70119 (Z704)	COMAN_1 24.0	360.0	200.0	360.0	360.0	360.0	360.0	360.0	360.0
70120 (Z704)	COMAN_2 24.0	365.0	200.0	360.0	365.0	365.0	365.0	365.0	365.0
70777 (Z704)	COMAN_3 27.0	870.0	330.0	800.0	870.0	870.0	800.0	870.0	870.0
Zones 712 & 757	Southeastern Colorado Generation	1936.0 HS 1683.0 LA	10.0 HS 0.0 LA	1445.6	1900.0	1900.0	1097.5	1620.0	1620.0
Total				10,951.4	10,951.4	10,951.4	10,490.2	10,490.2	10,490.2
Big Sandy-Landsman Creek 230kV West-to-East Flow: (Stressed by Study Cases **13HS1a** and **13LA1a**)				-32.7	**79.1**	44.4	-46.2	**38.6**	4.3
Landsman Creek-Burlington 230 kV West-to-East Flow: (Stressed by Study Cases **13HS2a** and **13LA2a**)				17.3	78.2	**94.3**	3.5	38.4	**54.4**

Base case **13HS0** shows -32.7 MW flow on Big Sandy-Landsman Creek 230 kV line and 17.3 MW on Landsman Creek-Burlington 230 kV line.

Study case **13HS1a** stressed local unit and other generation in base case **13HS0** to increase the flow on Big Sandy-Landsman Creek 230 kV line to 79.1 MW.

Study case **13HS2a** stressed local unit and other generation in base case **13HS0** to increase the flow on Landsman Creek-Burlington 230 kV line to 94.3 MW.

Base case **13LA0** shows -46.2 MW flow on Big Sandy-Landsman Creek 230 kV line and 3.5 MW on Landsman Creek-Burlington 230 kV line.

Study case **13LA1a** stressed local unit and other generation in base case **13LA0** to increase the flow on Big Sandy-Landsman Creek 230 kV line to 38.6 MW.

Study case **13LA2a** stressed local unit and other generation in base case **13LA0** to increase the flow on Landsman Creek-Burlington 230 kV line to 54.4 MW.

Eight single line outages (breaker to breaker) were selected for the contingency study, as shown below:

1) Lincoln-Midway 230 kV,
2) Lincoln-Big Sandy 230 kV,
3) Big Sandy-Landsman Creek 230 kV,
4) Landsman Creek-Burlington 230 kV,
5) North Yuma-Wray 230 kV,
6) North Yuma-Story 230 kV,
7) Big Sandy-Last Chance 115 kV, and
8) Burlington-Bonny Creek-South Fork 115 kV.

All transmission facilities in Western (Areas 70) and Excel Energy (Area 73) are monitored. The resulting planning criteria violations including voltage, voltage deviation and transmission loading in the study area are summarized in Table 3. Note that planning criteria violations due to generation dispatches in remote areas are ignored.

Table 3: Summary of Planning Criteria Violations
(West-to-East Flow)

System Conditions	Monitored Elements	Rating (MVA)	Base Case 13HS0	Study Case 13HS1a	Study Case 13HS2a	Base Case 13LA0	Study Case 13LA1a	Study Case 13LA2a
All Lines in Service	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
Lincoln-Midway 230 kV Out (73531-73413)	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
	Voltage deviation violation		none	none	none	none	none	none
Lincoln-Big Sandy 230 kV Out (73531-73018)	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
	Voltage deviation violation		none	none	none	none	none	none
Big Sandy-Landsman Creek 230 kV Out (73018-72710)	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
	Voltage deviation violation		none	none	none	none	none	none
Landsman Creek-Burlington 230 kV Out (72710-73036)	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
	Voltage deviation violation		none	none	none	none	none	none
North Yuma-Wray 230 kV Out (73143-73224)	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
	Voltage deviation violation		none	none	none	none	none	none
North Yuma-Story 230 kV Out (73143-73192)	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
	Voltage deviation violation		none	none	none	none	none	none
Big Sandy-Last Chance 115 kV Out (73017-73125)	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
	Voltage deviation violation		none	none	none	none	none	none
Burlington-Bonny Creek-South Fork 115 kV (73035-73025-73185)	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
	Voltage deviation violation		none	none	none	none	none	none

The table shows no planning criteria violation for West-to-East flows on Big Sandy-Landsman Creek 230 kV and Landsman Creek-Burlington 230 kV lines.

East-to-West Flow:

Two study cases, **13HS1b** and **13LA1b**, derived from the base cases, **13HS0** and **13LA0**, are used to study the East-to-West flows on the Burlington-Landsman Creek 230 kV line. Another two study cases, **13HS2b** and **13LA2b**, also derived from the base cases, **13HS0** and **13LA0**, are used to study the East-to-West flows on the Landsman Creek-Big Sandy 230 kV line. The respective stressed generation for the four study cases, including Lincoln and Burlington unit generation; and other generation in southeastern Colorado and Montana/Idaho areas, are shown in Table 4. Red numbers under the study cases indicate the generation that are different from the base cases.

Table 4: Stressed Generation Dispatches for Various Study Cases
(East-to-West Flow)

Number	Name	Pmax	Pmin	Base Case 13HS0	Study Case 13HS1b	Study Case 13HS2b	Base Case 13LA0	Study Case 13LA1b	Study Case 13LA2b
		(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
Area 62 & 60	Montana & Idaho Generation	8823.1 HS 8823.1 LA	1062.4 HS 1062.4 LA	7617.8	8650.0	8650.0	7616.7	8650.0	8650.0
73181 (Z756)	SIDNEYDC 230	200.0	-200.0	200.0	200.0	200.0	200.0	200.0	200.0
73302 (Z752)	BRLNGTN1 13.8	50.0	25.0	29.0	50.0	50.0	0.0	50.0	45.0
73303 (Z752)	BRLNGTN2 13.8	50.0	25.0	29.0	50.0	50.0	0.0	50.0	45.0
72714 (Z751)	KIT.CARSON 0.69	51.0	2.4	51.0	0.0	51.0	51.0	0.0	51.0
73532 (Z752)	LINCOLN1 13.8	68.0	40.0	0.0	0.0	0.0	0.0	0.0	0.0
73533 (Z752)	LINCOLN2 13.8	68.0	40.0	59.0	0.0	0.0	0.0	0.0	0.0
70119 (Z704)	COMAN_1 24.0	360.0	200.0	360.0	0.0	0.0	360.0	0.0	0.0
70120 (Z704)	COMAN_2 24.0	365.0	200.0	360.0	220.0	220.0	365.0	220.0	220.0
70777 (Z704)	COMAN_3 27.0	870.0	330.0	800.0	350.0	350.0	800.0	350.0	350.0
Zones 712 & 757	Southeastern Colorado Generation	1936.0 HS 1683.0 LA	10.0 HS 0.0 LA	1445.6	1431.4	1380.4	1097.5	970.2	929.2
Total				10,951.4	10,951.4	10,951.4	10,490.2	10,490.2	10,490.2
Burlington-Landsman Creek 230 kV East-to-West Flow: (Stressed by Study Cases **13HS1b** and **13LA1b**)				-17.3	**53.8**	39.8	-3.5	**98.1**	77.6
Landsman Creek-Big Sandy 230kV East-to-West Flow: (Stressed by Study Cases **13HS2b** and **13LA2b**)				32.9	53.7	**90.0**	46.5	97.9	**127.7**

Base case **13HS0** shows -17.3 MW on Burlington-Landsman Creek 230 kV line and 32.9 MW on Landsman Creek-Big Sandy 230 kV line.

Study case **13HS1b** stressed local unit and other generation in base case **13HS0** to increase the flow on Burlington-Landsman Creek 230 kV line to 53.8 MW.

Study case **13HS2b** stressed local unit and other generation in base case **13HS0** to increase the flow on Landsman Creek-Big Sandy 230 kV line to 90.0 MW.

Base case **13LA0** shows -3.5 MW on Burlington-Landsman Creek 230 kV line and 46.5 MW on Landsman Creek-Big Sandy 230 kV line.

Study case **13LA1b** stressed local unit and other generation in base case **13LA0** to increase the flow on Burlington-Landsman Creek 230 kV line to 98.1 MW.

Study case **13LA2b** stressed local unit and other generation in base case **13LA0** to increase the flow on Landsman Creek-Big Sandy 230 kV line to 127.7 MW. Note that the total of Burlington and Kit Carson generation is limited to 141 MW (when both Lincoln (also known as Limon) generating units are off line) according to Operating Procedure 105: The combined operation of Limon and Burlington network resources, as shown in Appendix C.

The same eight single line outages, as selected in the "West-to-East Flow" section, are used to perform the contingency study.

All transmission facilities in Western (Areas 70) and Excel Energy (Area 73) are monitored. The resulting planning criteria violations including voltage, voltage deviation and transmission loading in the study area are summarized in Table 5. Note that planning criteria violations due to generation dispatches in remote areas are ignored.

Table 5: Summary of Planning Criteria Violations
(East-to-West Flow)

System Conditions	Monitored Elements	Rating (MVA)	Base Case 13HS0	Study Case 13HS1b	Study Case 13HS2b	Base Case 13LA0	Study Case 13LA1b	Study Case 13LA2b
All Lines in Service	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
Lincoln-Midway 230 kV Out (73531-73413)	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
	Voltage deviation violation		none	none	none	none	none	none
Lincoln-Big Sandy 230 kV Out (73531-73018)	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
	Voltage deviation violation		none	none	none	none	none	none
Big Sandy-Landsman Creek 230 kV Out (73018-72710)	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
	Voltage deviation violation		none	none	none	none	none	none
Landsman Creek-Burlington 230 kV Out (72710-73036)	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
	Voltage deviation violation		none	none	none	none	none	none
North Yuma-Wray 230 kV Out (73143-73224)	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
	Voltage deviation violation		none	none	none	none	none	none
North Yuma-Story 230 kV Out (73143-73192)	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
	Voltage deviation violation		none	none	none	none	none	none
Big Sandy-Last Chance 115 kV Out (73017-73125)	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
	Voltage deviation violation		none	none	none	none	none	none
Burlington-Bonny Creek-South Fork 115 kV (73035-73025-73185)	Loading violation		none	none	none	none	none	none
	Voltage violation		none	none	none	none	none	none
	Voltage deviation violation		none	none	none	none	none	none

The table shows no planning criteria violation for East-to-West flows on Burlington-Landsman Creek 230 kV and Landsman Creek-Big Sandy 230 kV lines.

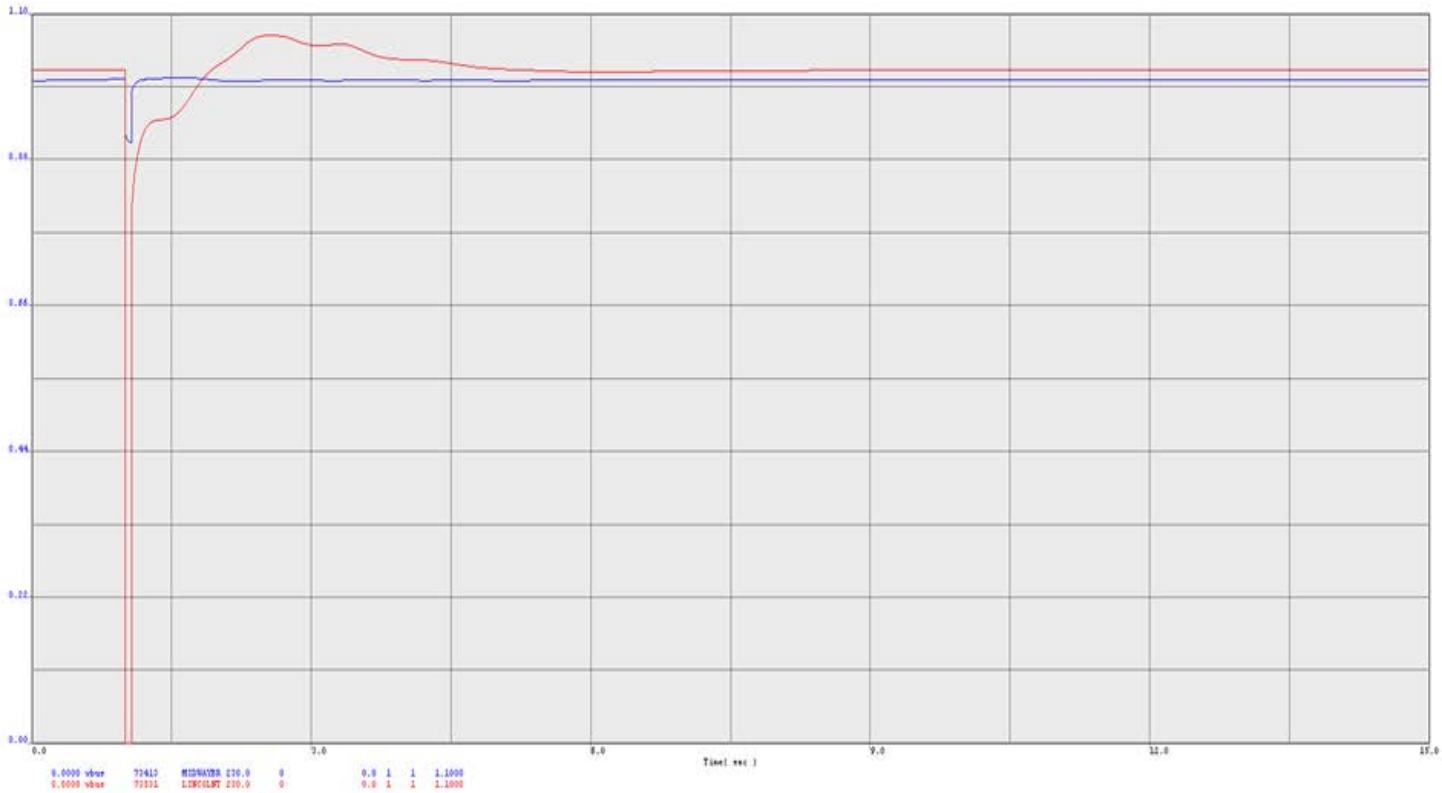
Transient Stability Study Results

Based on the developed study cases, study case **13HS2a** is mostly stressed by the local generation and was chosen to perform the transient stability study. An equivalent PSLF case **13HS2a_GE** was created to perform the following transient stability simulations.

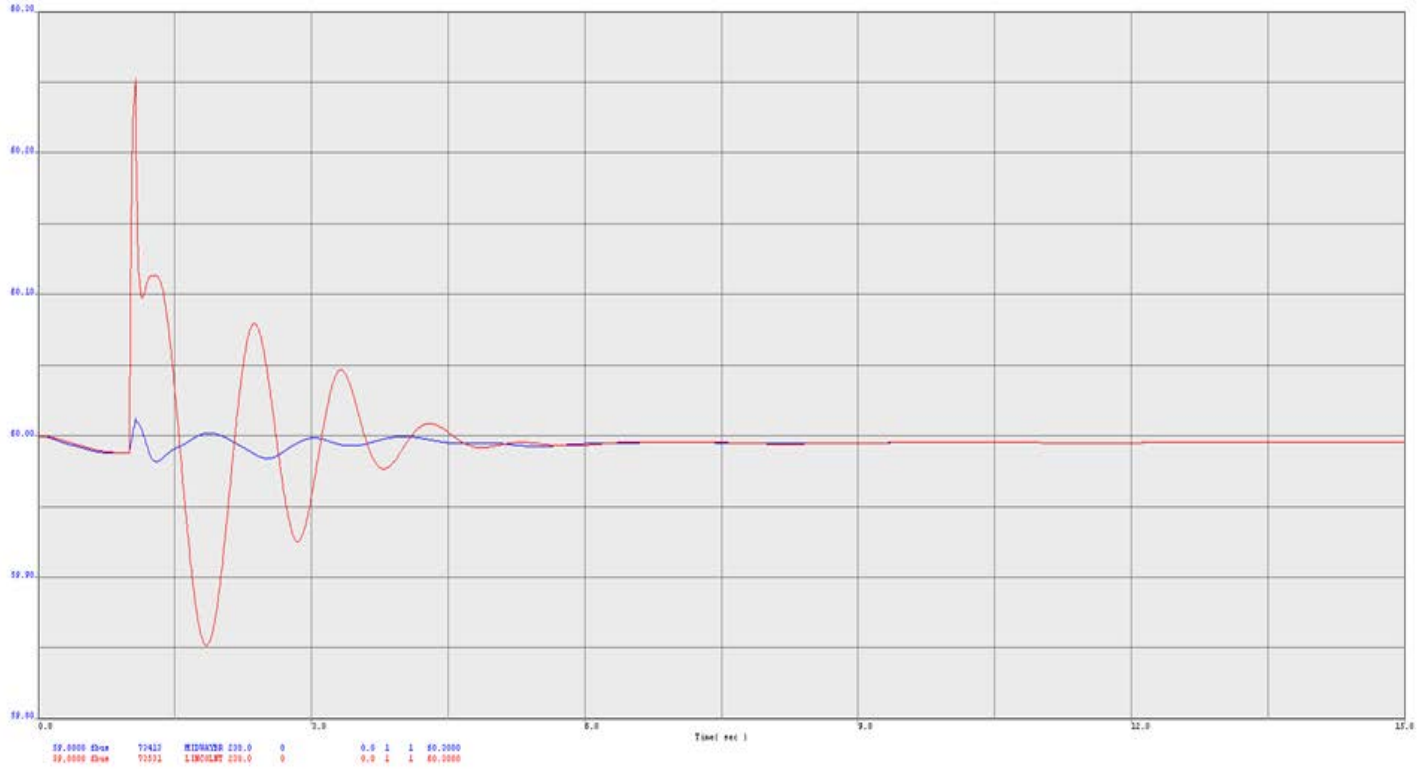
Simulation 1: 3-ϕ Lincoln 230 kV Fault and Loss of the Lincoln-Midway 230 kV Line.
Simulation 2: 3-ϕ Big Sandy 230 kV Fault and Loss of the Big Sandy-Landsman Creek 230 kV Line

The switching sequence is that the 3 phase fault was applied at 1.0 second and the faulted line was cleared in 4 cycles.

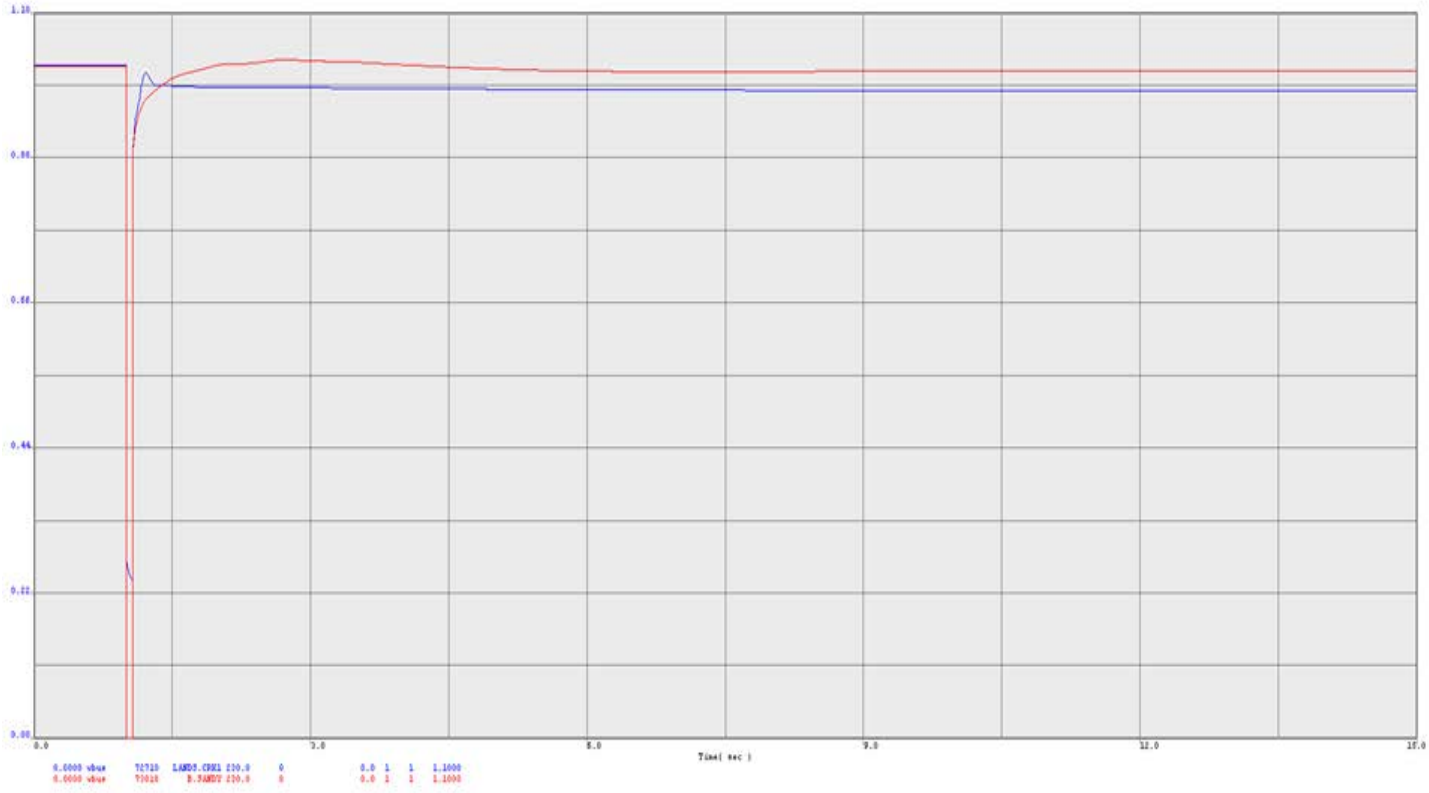
The selected voltage and frequency dynamic responses for **Simulation 1** are shown in Plot 1 and Plot 2, respectively. The selected voltage and frequency dynamic responses for **Simulation 2** are shown in Plot 4 and Plot 5, respectively. These plots indicate no transient stability violations according to Tri-State's planning criteria (Appendix A). Tri-State's criteria are consistent with the planning criteria of WECC and NERC.



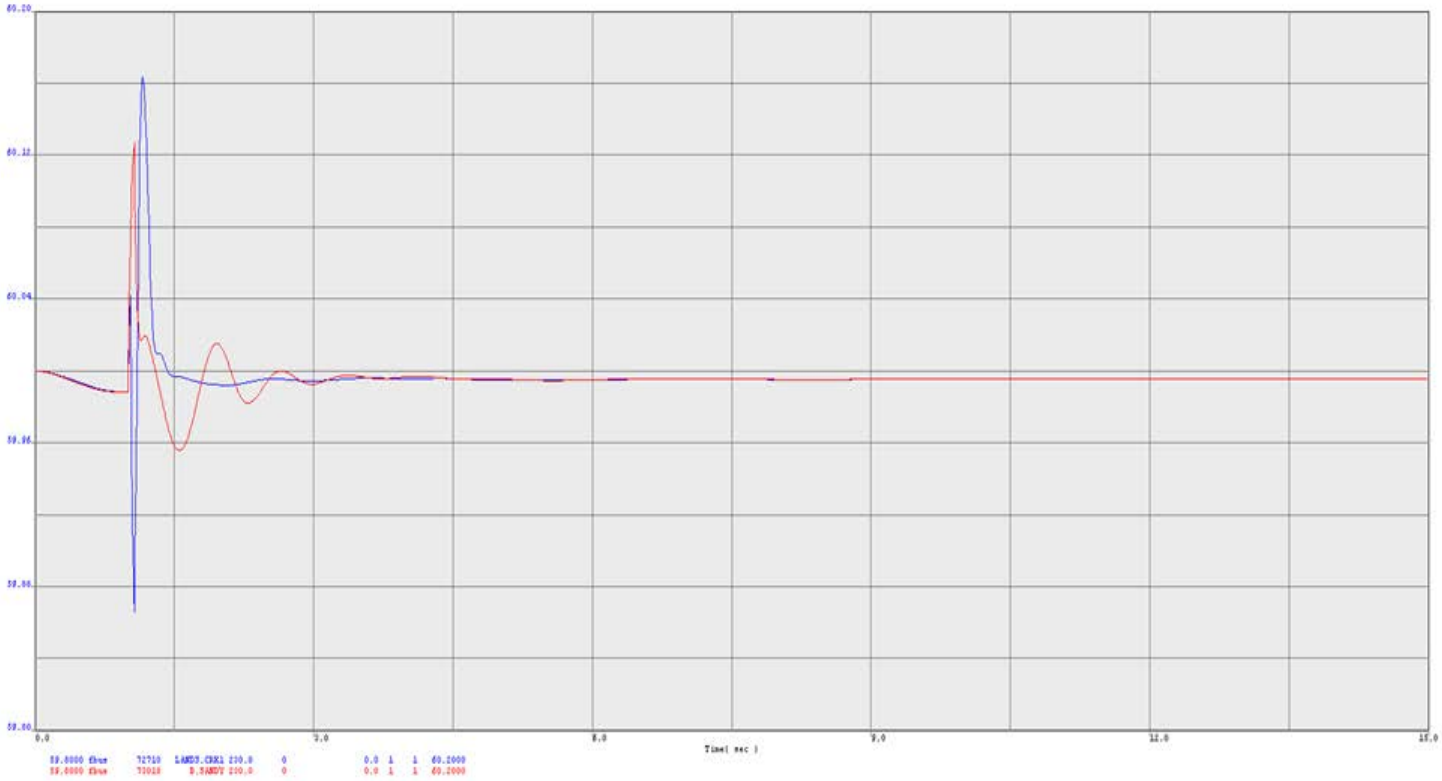
Plot 1: Voltage Response for Simulation 1



Plot 2: Frequency Response for Simulation 1



Plot 3: Voltage Response for Simulation 2



Plot 4: Frequency Response for Simulation 2

Conclusions

The study models various generation dispatches and load levels to increase the Big Sandy-Landsman Creek 230 kV line and Landsman Creek-Burlington 230 kV line flows in both West-to-East and East-to-West directions. The generation dispatches include local and other remote generators. Load levels include heavy summer and light autumn loads.

The power flow study results, as summarized in Tables 3 and 5, demonstrate that there are no system performance violations under all lines in service and single line outage conditions. In addition, the transient stability results indicate no dynamic violations. As a result, it is concluded that the TTCs for Big Sandy-Landsman Creek 230 kV and Landsman Creek-Burlington 230 kV lines are not "reliability limited". The TTCs are therefore defaulted to the System Operating Limits (SOL) of the lines, as shown in Table 6 below.

Table 6: TTCs

Breaker to Breaker Line	West-to-East TTC (MVA)	Reason
Big Sandy-Landsman Creek 230 kV	275.0	The TTC values are defaulted to the system operating limits (SOL) of these lines because the power flow study results, upon applying Operating Procedure 105, could not find the reliability-limited flows on these lines under various stressed generation dispatches and load levels in the study areas.
Landsman Creek-Burlington 230 kV	275.0	
	East-to-West TTC (MVA)	From R2 MOD-029-1a: When it is impossible to actually simulate a reliability-limited flow in a direction counter to the prevailing flow, set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction.
Big Sandy-Landsman Creek 230 kV	275.0	
Landsman Creek-Burlington 230 kV	275.0	

Appendix A: Planning Criteria

Table A 1

Summary of Tri-State Steady-State Planning Criteria

System Condition	Operating Voltages [1] (per unit)		Maximum Loading [2] (Percent of Continuous Rating)	
	Maximum	Minimum	Transmission Lines	Other Facilities
Normal	1.05	0.95	80/100	100
N – k	1.10	0.90	100	100

(1) Exceptions may be granted for high side buses of Load-Tap-Changing (LTC) transformers that violate this criterion, if the corresponding low side busses are well within the criterion.

(2) The continuous rating is synonymous with the static thermal rating. Facilities exceeding 80% criteria will be flagged for close scrutiny. By no means, shall the 100% rating be exceeded without regard in planning studies.

Table A 2

Tri - State Voltage Criteria				
Conditions	**Operating Voltages**	**Delta-V**	**Areas**	**Bus List Name in Spreadsheet**
Normal	0.95 - 1.05			
Contingency N-1	0.90 - 1.10	7%	Northeastern New Mexico	NE New Mexico
Contingency N-1	0.90 - 1.10	7%	Southern New Mexico	S New Mexico
Contingency N-1	0.90 - 1.10	6%	Other buses in PNM area	O New Mexico
Contingency N-1	0.90 - 1.10	7%	Western Colorado	W Colorado
Contingency N-1	0.90 - 1.10	7%	Southern Colorado	S Colorado
Contingency N-1	0.90 - 1.10	6%	Other Tri-State areas	
Contingency N-2	0.90 - 1.10	10%	All	

Tri-State Generation and Transmission Assoc. (TP) –Reactive Power & Voltage Regulation Requirements for Generation Interconnections

A. Tri-State's Steady State VAR, and Voltage Regulation Requirements:
Note - while these generally make reference to wind generation facilities, they shall apply to all generation interconnections, PV solar plants may be exempt if the requirement is not feasible.

1) All interconnections are subject to detailed study and may require mitigation in excess of minimums imposed by published standards, according to the best judgement of Tri-State engineers. The IC's Large Generating Facilities (LGF) shall be capable of either producing or absorbing reactive power (VAR) as measured at the HV POI bus at an equivalent 0.95 p.f., across the range of near 0% to 100% of facility MW rating, with the magnitude of VAR calculated on the basis of nominal POI voltage (1.0 p.u. V). This would be the net MVAR able to be either produced or absorbed by the IF facility, depending upon the voltage regulating conditions at the POI (see next item).

2) The POI voltage range where the IC's LGF may be required to produce VAR is from 0.90 p.u. V through 1.04 p.u. V. In this range the IC facilities are being utilized to help support or raise the POI bus voltage.

3) The POI voltage range where the IC's LGF may be required to absorb VAR is from 1.02 p.u. V through 1.10 p.u. V. In this range the IC facilities are being utilized to help reduce the POI bus voltage.

4) Note that the POI voltage range where the IC's LGF may be required to either produce VAR or absorb VAR is 1.02 p.u. V through 1.04 p.u. V, with the typical target regulating voltage being 1.03 p.u. V.

5) The IC's LGF may supply reactive power from the generators, from the generators' inverter systems alone (if capable), or a combination of the generators, generators' inverter systems plus switched capacitor banks and/or reactors, or continuously variable STATCOM or SVC type systems. The IC's LGF is required to supply a portion of the reactive power (VAR) in a continuously variable fashion, such as supplied from either the generators, the generators' inverter systems, or a STATCOM or SVC system. The amount of continuously variable VAR shall be a value equivalent to a minimum of 0.95 p.f. produced or absorbed at the generator terminal Low Voltage (LV) bus, across the full range (0 to 100%) of rated MW output. The remainder of VAR required to meet the 0.95 p.f. net criteria at the HV POI bus may be achieved with switched capacitors and reactors, so long as the resultant step-change voltage is no greater than 3% of the POI operating bus voltage. This step change voltage magnitude shall be initially calculated based upon the minimum system (N-1) short circuit POI bus MVA level as supplied by the TP.

6) Under conditions when the IC's LGF is not producing any real power (near 0 MW, and typically less than 2 MVAR), the reactive power exchange at the POI shall be near 0 MVAR ("VAR neutral"). This condition assumes that the facility needs to remain energized to supply base-level station-service "house power" for the control facilities, maintain wind turbines on turning gear, etc., and that tripping open the IC transmission line supply is not a normal or acceptable means to create this VAR neutral condition. In this non-generating mode, the IC Facility appears as a transmission connected load customer, and therefore must meet TP's requirements for load p.f., which requires that the load p.f. be 0.95 or better.

7) All interconnections are subject to additional detailed study, utilizing more complex models and software such as PSCAD, EMTP, or similar, and may require mitigation in excess of minimums imposed by published standards, according to the best judgement of the TP's engineers.

Basic WECC Dynamic Criteria:

Tri-State's dynamic reactive power and voltage control / regulation criteria are in accordance with the NERC/WECC dynamic performance standard shown in Figure W-1 and Table W-1 of the "TPL-(001 thru 004)-WECC-1-CR, System Performance Criteria" dated April 18, 2008.. Additional Tri-State dynamic reactive power and voltage criteria are listed below.

B. Tri-State's Dynamic VAR and Low Voltage Ride-Through Requirements (consistent with FERC Order 661-A):

Note - while these requirements generally make reference to wind generation facilities, they shall apply to all types of generation interconnections. PV solar plants may be exempt if the requirement is not feasible.

1) The IC's LGF shall be able to meet the dynamic response Low Voltage Ride-Through (LVRT) requirements consistent with the latest WECC / NERC criteria. In particular, as per the Tri-State LGIP, **`Error! Reference source not found.`** and FERC Order 661a for LVRT (applicable to Wind Generation Facilities).

2) Generating plants are required to remain in service during and after faults, three-phase or single line-to-ground (SLG) whichever is worse, with normal total clearing times in the range of approximately 4 to 9 cycles, SLG faults with delayed clearing, and subsequent post-fault voltage recovery to pre-fault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the circuit breaker clearing times of the effected system to which the IC facilities are interconnecting. The maximum clearing time the generating plant shall be required to withstand for a fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the Point of Interconnection (POI). To elaborate, before time 0.0, the voltage at the POI is the nominal voltage. At time 0.0, the voltage drops. The plant must stay online for at least 0.15 seconds regardless of voltage during the fault. Further, if the voltage returns to 90 percent of the nominal voltage within 3 seconds of the beginning of the voltage drop, the plant must continuously stay online. The Interconnection Customer may not disable low voltage ride-through equipment while the wind plant is in operation.

3) This requirement does not apply to faults that would occur between the generator terminals and the POI.

4) Generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

5) Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAR Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.

Table A 3

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Table A 4

WECC DISTURBANCE-PERFORMANCE TABLE OF ALLOWABLE EFFECTS ON OTHER SYSTEMS

NERC and WECC Categories	Outage Frequency Associated with the Performance Category (outage/year)	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post Transient Voltage Deviation Standard (See Note 2)
A	Not Applicable	Nothing in addition to NERC		
B	≥ 0.33	Not to exceed **25%** at load buses or **30%** at non-load buses. Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6** Hz for 6 cycles or more at a load bus.	Not to exceed **5%** at any bus.
C	0.033 – 0.33	Not to exceed **30%** at any bus. Not to exceed **20% for more than 40 cycles** at load buses.	Not below **59.0** Hz for 6 cycles or more at a load bus.	Not to exceed **10%** at any bus.
D	< 0.033	Nothing in addition to NERC		

Notes:

1. *The WECC Disturbance-Performance Table applies equally to either a system with all elements in service, or a system with one element removed and the system adjusted.*

2. *As an example in applying the WECC Disturbance-Performance Table, a Category B disturbance in one system shall not cause a transient voltage dip in another system that is greater than 20% for more than 20 cycles at load buses, or exceed 25% at load buses or 30% at non-load buses at any time other than during the fault.*

3. *Additional voltage requirements associated with voltage stability are specified in Standard I-D. If it can be demonstrated that post transient voltage deviations that are less than the values in the table will result in voltage instability, the system in which the disturbance originated and the affected system(s) should cooperate in mutually resolving the problem.*

4. *Refer to Figure W-1 for voltage performance parameters.*

5. *Load buses include generating unit auxiliary loads.*

6. *To reach the frequency categories shown in the WECC Disturbance-Performance Table for Category C disturbances, it is presumed that some planned and controlled islanding has occurred. Underfrequency load shedding is expected to arrest this frequency decline and assure continued operation within the resulting islands.*

7. *For simulation test cases, the interconnected transmission system steady state loading conditions prior to a disturbance should be appropriate to the case. Disturbances should be simulated at locations on the system that result in maximum stress on other systems. Relay action, fault clearing time, and reclosing practice should be represented in simulations according to the planning and operation of the actual or planned systems. When simulating post transient conditions, actions are limited to automatic devices and no manual action is to be assumed.*

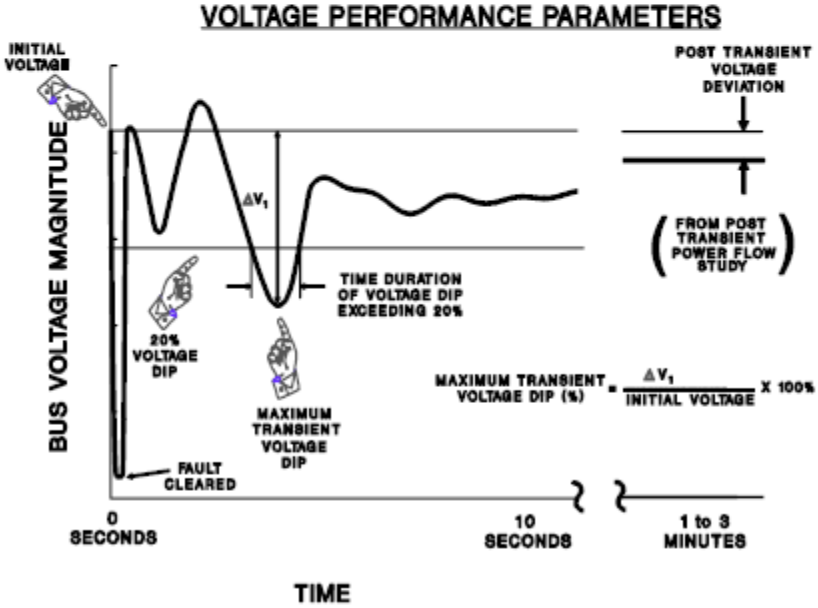


Figure W-1

Table A 5

Table 1

WSCC VOLTAGE STABILITY CRITERIA(*)

Performance Level	Disturbance (1)(2)(3)(4) Initiated By: Fault or No Fault DC Disturbance	MW Margin (P-V Method) (5)(6)(7)	MVAR Margin (V-Q Method) (6)(7)
A	Any element such as: One Generator One Circuit One Transformer One Reactive Power Source One DC Monopole	≥ 5%	Worst Case Scenario (8)
B	Bus Section	≥ 2.5%	50% of Margin Requirement in Level A
C	Any combination of two elements such as: A Line and a Generator A Line and a Reactive Power Source Two Generators Two Circuits Two Transformers Two Reactive Power Sources DC Bipole	≥ 2.5%	50% of Margin Requirement in Level A
D	Any combination of three or more elements such as: Three or More Circuits on ROW Entire Substation Entire Plant Including Switchyard	> 0	> 0

(1) This table applies equally to the system with all elements in service and the system with one element removed and the system readjusted (see Section 2.2).

(2) For application of this criteria within a member system, controlled load shedding is allowed to meet Performance Level A (see Section 2.2 for a description of provisions for application of this criteria within a member system).

(3) The list of element outages in each Performance Level is not intended to be different than the Disturbance Performance Table in the WECC Reliability Criteria. Additional element outages have been added to this table to show more examples of contingencies. Determination of credibility for contingencies for each Performance Level is based on the definitions used in the existing WECC Reliability Criteria.

(4) Margin for N-0 (base case) conditions must be greater than the margin for Performance Level A.

(5) Maximum operating point on the P axis must have a MW margin equal to or greater than the values in this table as measured from the nose point of the P-V curve for each Performance Level.

(6) Post-transient analysis techniques shall be utilized in applying the criteria.

(7) Each member system should consider, as appropriate, the uncertainties in Section 2.3 to determine the required margin for its system.

(8) The most reactive deficient bus must have adequate reactive power margin for the worst single contingency to satisfy either of the following conditions, whichever is worse: (i) a 5% increase beyond maximum forecasted loads or (ii) a 5% increase beyond maximum allowable interface flows. The worst single contingency is the one that causes the largest decrease in the reactive power margin.

(*) Table 1 is an excerpt from the WSCC Reliability Criteria for Transmission System Planning in effect at the time of this document's approval. The most current version of the Council's Table of Allowable Effects on Other Systems should be referred to when conducting studies.

Final Report – May 1998

Appendix B: Standard MOD-029-1a — Rated System Path Methodology

A. Introduction

1. **Title:** **Rated System Path Methodology**

2. **Number:** **MOD-029-1a**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.

4. **Applicability:**

   4.1. Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   4.2. Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R1.1. The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:

R1.1.1. Includes at least:

R1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.

R1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)

R1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)

R1.1.2. Models all system Elements as in-service for the assumed initial conditions.

R1.1.3. 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.

R1.1.4. Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).

R1.1.5. Uses Load forecast by Balancing Authority.

R1.1.6. Uses Transmission Facility additions and retirements.

R1.1.7. Uses Generation Facility additions and retirements.

R1.1.8. Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon.

R1.1.9. Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.

R1.1.10. Includes any other modeling requirements or criteria specified in the ATCID.

R1.2. Uses Facility Ratings as provided by the Transmission Owner and Generator Owner

R2. The Transmission Operator shall use the following process to determine TTC: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R2.1. Except where otherwise specified within MOD-029-1, 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:

R2.1.1. When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.

R2.1.2. When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.

R2.1.3. Uncontrolled separation shall not occur.

R2.2. Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependant on a Special Protection System (SPS), 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.

R2.3. For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.

R2.4. For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

R2.5. The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path.

Do this 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 R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.

R2.6. Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.

R2.7. 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.

R2.8. Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

R3. Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R4. Within seven calendar days of the finalization of the study report, the Transmission Operator 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. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R5. When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

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

Where:

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.

R6. When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

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

Where:

$NITS_{NF}$ 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.

R7. When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

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

Where

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 their ATCID.

R8. When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

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

Where:

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 its ATCID.

C. Measures

M1. Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)

M1.1. Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)

M1.2. The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)

M1.3. The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)

M1.4. The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)

M2. Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).

M3. Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)

M4. Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

M5. Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path. (R3)

M6. Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)

M7. The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the

originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)

M8. The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)

M9. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)

M10. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

- The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:
- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)

- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

  The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)
R2	One or both of the following: • The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include one required item in the study report required in R2.8.	One or both of the following: • The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include two required items in the study report required in R2.8.	One or both of the following: • The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include three required items in the study report required in R2.8.	One or more of the following: • The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6. • The Transmission Operator did not apply R2.7. • The Transmission Operator does not include four or more required items in the study report required in R2.8

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).
R4.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized.
R5.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R6.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R7.	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).
R8.	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).

Version History

Version	Date	Action	Change Tracking
1	8/26/2008	Adopted by NERC Board of Trustees	
1a	Board approved 11/05/2009	Interpretation of R5 and R6	Interpretation (Project 2009-15)

Appendix 1

Requirement Number and Text of Requirement
MOD-001-01 Requirement R2: **R2.** Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): **R2.1.** Hourly values for at least the next 48 hours. **R2.2.** Daily values for at least the next 31 calendar days. **R2.3.** Monthly values for at least the next 12 months (months 2-13). **MOD-001-01 Requirement R8:** **R8.** Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: **R8.1.** Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation. **R8.2.** Daily values, once per day. **R8.3.** Monthly values, once per week.
Question #1
Is the "advisory ATC" used under the NYISO tariff subject to the ATC calculation and recalculation requirements in MOD-001-1 Requirements R2 and R8? If not, is it necessary to document the frequency of "advisory" calculations in the responsible entity's Available Transfer Capability Implementation Document?
Response to Question #1
Requirements R2 and R8 of MOD-001-1 are both related to Requirement R1, which defines that ATC methodologies are to be applied to specific "ATC Paths." The NERC definition of ATC Path is "Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path." Based on a review of the language included in this request, the NYISO Open Access Transmission Tariff, and other information posted on the NYISO Web site, it appears that the NYISO does indeed have multiple ATC Paths, which are subject to the calculation and recalculation requirements in Requirements R2 and R8. It appears from reviewing this information that ATC is defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO's "advisory ATC" is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths. The second part of NYISO's question is only applicable if the first part was answered in the

negative and therefore will not be addressed.

Requirement Number and Text of Requirement

MOD-029-01 Requirements R5 and R6:

R5. When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:

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

Where:

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.

R6. When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm:

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

Where:

$NITS_{NF}$ 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.

Question #2

Could OS_F in MOD-029-1 Requirement R5 and OS_{NF} in MOD-029-1 Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?

Response to Question #2

This request for interpretation and the NYISO Open Access Transmission Tariff describe the NYISO's concept of "Transmission Flow Utilization;" however, it is unclear whether or not Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6 are incorporated into "Transmission Flow Utilization." Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Service" would be inappropriate.

Appendix C: Operating Procedure 105:
The combined operation of Limon and Burlington network resources

OPERATING PROCEDURE OP-105
(12.26.2012)

A. Introduction

1. **Title: The combined operation of Limon and Burlington network resources.**

2. **Number**: OP-105

3. **Summary:** Due to transmission constraints, the generation at Lincoln, Kit Carson, and Burlington has seasonal restrictions.

4. **Time Duration:** This Operating Procedure is only required for an Interim period and will be removed when the planned Burlington to Wray 230 kV line is completed and becomes operational, or until other transmission system modifications are made that mitigate this need.

B. Procedure

- Tri-State System Operations Operators will continuously monitor the loading on the Big Sandy to Last Chance 115 kV and Idalia – Wray 115 kV lines and request generation reduction by Tri-State Merchant to mitigate thermal overloads. The amount of combined Limon to Burlington area generation reductions on a real time basis will be equal to the amount by which the Big Sandy to Last Chance and/or Idalia – Wray 115 kV lines actual loadings exceed the current thermal rating of the lines.

- Tri-State Merchant will respond to any such mitigation request in a timely manner to resolve the overload within a 15 minute time period. This will ensure that Tri-State Operations meet the required 30 minute WECC response time to correct thermally overloaded lines.

- Tri-State Operations will also provide a seasonal table of combined Limon/Burlington Network Resource generation limits to Tri-State Merchant based upon various operating scenarios. This table will recognize that the next most limiting N-1 outage must be accommodated without any resulting line overloads, violation of operating parameters, and loss of Network Resource generation. Tri-State Reliability will monitor the combined Limon/ Burlington Network Resource generation levels to make sure that they don't exceed the applicable generation limit. The initial seasonal limits are shown in Attachment A.

- Tri-State Merchant will not exceed the seasonal combined Limon/Burlington Network Resource generation limits provided by Tri-State Operations in Attachment A of this procedure.

D. Background

A restricted Network Resource designation is granted to the 51 MW Kit Carson Wind power generation project near Burlington Substation relative to a request made by a Tri-State Energy Resources group (Tri-State Merchant), whom is a Network Customer of Tri-State Transmission (Tri-State Operations). This restricted Network Resource designation is required due to transmission system limitations during certain system conditions. The projected operating scenarios of concern occur during light winter load conditions only when all existing Burlington and Limon combustion turbines plus the 51 MW Kit Carson Wind power project near Burlington are operated at high generation levels. The most limiting condition is encountered when the loads fed out of the Burlington Substation are low (approximately 16 MW). This can result in a thermal overload of the existing WAPA's Big Sandy - Last Chance 115 kV line rated at 109 MVA under the Lincoln to Midway 230 kV line outage and overload of the existing Tri-State's Idalia – Wray 115 kV line rated at 120 MVA under the Landsman Creek to Big Sandy 230 kV line outage . This operating scenario can be mitigated by reducing the output of the combined Limon/Burlington Network Resource generation levels, which are dispatched by Tri-State Merchant. The combined Burlington Network Resource consists of the existing Limon/Burlington Combustion Turbines and the new 51 MW Kit Carson Wind power project.

Tri-State Operations Approval:

Date: 12/26/2012

Keith Carman
Senior Manager
Transmission System Operations

Network Transmission Customer Approval:

Date: 12/26/12

Dan Walter
Senior Manager
Tri-State Energy Markets

ATTACHMENT A

COMBINED BURLINGTON NETWORK RESOURCE LIMIT
SUMMER SEASON OF 2013
Date issued December, 2012

Limon 1 CT Status (Pmax = 68MW)	Limon 2 CT Status (Pmax = 68MW)	Limiting Outage	*Burlington NR Generation Limit
ON	ON	None	151
ON	OFF	None	151

***Note: Burlington NR = Burlington #1 (Pmax HS 50 MW) + Burl #2 (Pmax HS 50 MW) + Kit Carson Wind (Pmax 51 MW**

COMBINED BURLINGTON NETWORK RESOURCE LIMIT
WINTER SEASON OF 2012/2013
Date issued December, 2012

Limon 1 CT Status (Pmax = 77 MW)	Limon 2 CT Status (Pmax = 77 MW)	Limiting Outage	*Burlington NR Generation Limit
ON	ON	Lincoln to Midway 230 kV	93
ON	OFF	None	171
OFF	OFF	Landsman Creek. to B. Sandy 230 kV	141

***Note: Burlington NR = Burlington #1 (Pmax HW 60 MW) + Burl #2 (Pmax HW 60 MW) + Kit Carson Wind (Pmax 51 MW)**