Impacts of Reduced Generation on Transmission in Northern Nevada

1. Executive Summary

This report provides results of an initial screening to identify the scope and magnitude of possible transmission system issues resulting from an early retirement of two coal-fired generating plants in northern Nevada. Studies were conducted to determine how the performance of the transmission system in northern Nevada would change under several possible scenarios to replace the power generated at the North Valmy Power Plant ("NVPP") and the TS Power Plant ("TSPP"). The study results suggest that the replacement of NVPP and TSPP generation could exacerbate some post-contingency equipment loadings and bus voltage changes. The report also identifies examples of transmission system changes that are shown to mitigate the most prominent voltage changes for one specific condition associated with each of the generation replacement scenarios.

2. Plant Descriptions

The North Valmy Power Plant is located approximately fifteen miles northwest of Battle Mountain, Nevada and is comprised of two coal-fired steam turbine generators rated at 254 megawatts and 264 megawatts respectively. The TS Power Plant is located on Newmont Mining Corporation's TS Ranch approximately 60 miles west of Elko, Nevada and is comprised of a single coal-fired steam turbine rated at 242 megawatts.

3. Study Methodology

The North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) establish minimum reliability standards for the planning and operation of the transmission system in the western interconnection. WECC is in the process of approving an updated criterion TPL-001-WECC-CRT-3 "Transmission System Planning Performance" (included with supporting materials as Attachment A). The document's base planning criteria for single contingency event (P1) was used to screen for possible transmission problems resulting from reduced generation from NVPP and TSPP.

Figure 1 - Northern Nevada Transmission

Two different study methodologies were employed. Both methodologies are widely used by utilities and regional planning organizations to screen for potential future transmission system expansion needs:

A. Single Contingency Analysis

This analysis looks at the changes in transmission equipment loadings and in post-contingency bus steady-state voltages that result from the loss of transmission facilities due to a single cause (N-1 contingency). The PowerWorld Simulator was used to perform this analysis, and the WECC 2021 Heavy Summer II (WECC 21HS2, approved October 2015) powerflow base case was used as the starting point. WECC data is available to individuals that (1) at the discretion of WECC have demonstrated a legitimate need, and (2) have executed a non-disclosure agreement with WECC. This base case models peak summer load conditions during which the NVPP and TSPP power plants would normally be expected to run. Generation levels for NVPP and TSPP in the WECC 21HS2 case are 550 megawatts and 220 megawatts respectively. The list of Nevada transmission system N-1 contingencies used in this analysis was derived from a list used by the WestConnect planning region during development of their 2015 Regional Transmission Plan; multi-element transmission lines were changed to single N-1 contingencies. There are a total of 692 N-1 contingencies in the list.

For N-1 contingencies, the post-contingency loadings on transmission equipment cannot exceed the ratings of that equipment. The results of all of the contingencies modeled on all of the cases were screened to identify instances where the generation reductions at NVPP and TSPP resulted in post-contingency equipment loadings that exceeded the equipment ratings.

For N-1 contingencies (P1), WECC TPL-001-WECC-CRT-3 requires that:

- Post contingency bus voltages stay within 90% and 110% of their nominal values. (WR1.1.1.2)
- The difference between pre-contingency and post-contingency voltage values at load serving buses cannot exceed 8%[1]. (WR1.1.2)

The pre-contingency and post-contingency bus voltages for all of the contingencies modeled on all of the cases were screened to identify instances where contingencies resulted in violations of the above criteria for each of the generation replacement scenarios.

[1] Note that the criteria language makes no distinction as to the direction of the change, however the "rationale" offered for this requirement suggests that it is only intended to apply to voltage decreases (see Attachment A).

B. Transient Stability Analysis

This analysis looked at the transient voltage swings that occur immediately after a contingency and as the transmission system transitions to a new steady-state condition (i.e. the "path" that voltages take on the way from pre-contingency to post-contingency steady-state values identified above). The transient stability features of the PowerWorld Simulator were used to perform this analysis, along with the dynamic data associated with the WECC 21HS2 case.

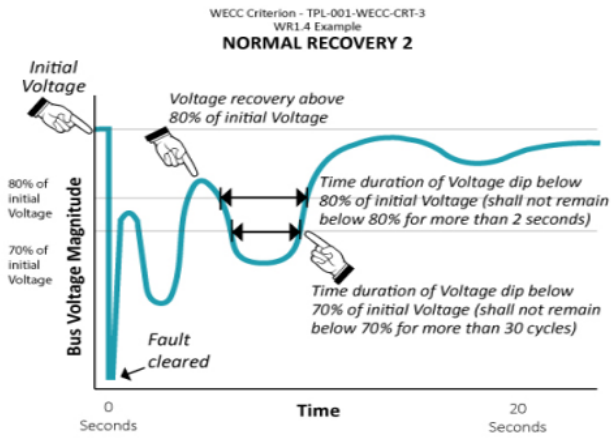


Figure 2 - Transient Voltage Recovery Example

WECC TPL-001-WECC-CRT-3 requires that:

- Bus voltages recover to 80% of their pre-contingency value within 20 seconds (after fault clearing). (WR1.1.3)
- Once recovered (above), bus voltages cannot dip below 70% of their pre-contingency value for more than 0.5 seconds or dip below 80% for more than 2 seconds.

A single transient stability simulation modeling a severe N-1 contingency was run for each of the generation replacement scenarios. The selection of the severe N-1 contingency was guided by the results of the single contingency analysis (above). The transient voltage behaviors of all buses in each simulation were screened to identify instances where the above criteria was violated.

C. Voltage Stability Analysis

This analysis determines if the contingency state is close to, or exceeds a voltage stability limit. The power flow magnitudes are incrementally increased by displacing generation with increased generation from one or more remote areas. The voltage stability tools available for the PowerWorld Simulator (named the PVQV tool) were used to perform this analysis.

4. Generation Replacement Scenarios

Four replacement scenarios were examined:

A. Imports from Several Adjacent Areas

In this scenario, the reduction in NVPP and TSPP generation is offset by small percentage decreases in load levels in areas adjacent to northern Nevada that allowed for increased generation imports from southern Nevada, Oregon-Washington, and Idaho. Widely dispersed replacement is potentially the "best case"

scenario for remote generation replacement. The relevant WECC path flows for this scenario are shown in Figure 3.

Transmission Path	Path Limit (MW)	Path Flows (MW)				
		WECC 21HS2	NVPP & TSPP OFF			
			Replace from Adjacent Areas	Replace from OR & ID	Replace From Arizona	NVE Load Reductions
ALTURAS PROJECT	+300/-300	112.1	204.1	301.3	113.4	113.6
IDAHO - SIERRA	+500/-360	-1.8	241.3	247.6	238.4	158.6
INTERMOUNTAIN - GONDER 230 KV	+200/0	71.2	117.9	116.4	113.5	94.0
PAVANT, INTRMTN - GONDER 230 KV	+440/-235	112.0	193.8	190.4	189.3	156.5
PG&E - SPP	+160/-150	-8.2	-6.6	-8.9	-12.3	-10.9
SILVER PEAK - CONTROL 55 KV	+17/-17	-5.4	-0.3	-2.3	0.9	-2.0

Figure 3 - Flows on Transmission Path into Northern Nevada for NVPP & TSPP Replacement Scenarios

B. Imports from Arizona

In this scenario, the reduction in NVPP and TSPP generation is offset by increased generation from the planned Bowie Power Station in Arizona. Replacement power from a single area can concentrate the transmission impacts of increased power imports on fewer facilities.

C. Imports from Oregon/Idaho

In this scenario, the reduction in NVPP and TSPP generation is offset by increased generation from existing plants in Oregon and Idaho.

D. Increases in In-State Energy Efficiency and Distributed Generation

In this scenario, the reduction in NVPP and TSPP generation is offset by increases in energy efficiency and distributed generation. These were modeled as 11.6% reductions in the base case levels of customer loads in Nevada. Narrowing the scope of load reductions to the Reno/Carson City area would have required a 60.2% reduction which was deemed to be unrealistic.

5. WECC Base Case Adjustments for Voltage Control

Each replacement scenario led to changes in power flows that in some cases required adjustments to the WECC 21HS2 base case modeling in order to maintain voltage levels within limits and optimize post contingency voltages. These base case adjustments included the switching (in or out) of shunt capacitors or shunt reactors, as well as changes to generator voltage control setpoints. The adjustments made for each replacement scenario are:

A. Imports from Several Adjacent Areas

- Close one line shunt reactor at the Harry Allen Substation on the Harry Allen to Robinson 500 kV line.
- Change the tap ratio on the Robinson 500/345 kV transformer from 0.9524 to 1.0024
- Move Automatic Voltage Regulator (AVR) control reference point for the Tracy Plant generators to the high-side bus of the generator step up transformers and set the control to hold at 102% of nominal voltage.
- Open three shunt capacitors on the 230 kV bus at Harry Allen Substation.
- Close one shunt reactor on the 500 kV bus at Harry Allen Substation.

B. Imports from Arizona

- Close one line shunt reactor at the Harry Allen Substation on the Harry Allen to Robinson 500 kV line.
- Change the tap ratio on the Robinson 500/345 kV transformer from 0.9524 to 1.0024
- Move AVR control reference point for the Tracy Plant generators to the high-side bus and set the control to hold at 102% of nominal voltage.
- Open three shunt capacitors on the 230 kV bus at the Harry Allen Substation.
- Close one shunt reactor on the 500 kV bus at the Harry Allen Substation.
- Close one shunt capacitor on the 63 kV bus at the Truckee Substation.

C. Imports from Oregon/Idaho

- Open one line shunt reactor at the Midpoint Substation on the Midpoint to Humboldt 345 kV line.
- Open one line shunt reactor at the Valmy Substation on the Valmy to Coyote Creek 345 kV line.
- Open one line shunt reactor at the Falcon Substation on the Falcon to Robinson 345 kV line.
- Close one line shunt reactor at the Robinson Substation on the Falcon to Robinson 345 kV line.
- Open one line shunt reactor at the Fort Sage Substation on the Fort Sage to Hilltop 345 kV line.
- Open two line shunt reactors at the Tracy Substation on the Tracy to Valmy 345 kV line.
- Close one line shunt reactor at the Gondor Substation on the Gondor to Robinson 345 kV line.
- Close one line shunt reactor at Humbolt Substation on the Humbolt to Midpoint 345 kV line.

D. Increases in In-State Energy Efficiency and Distributed Generation

- No changes.

6. Study Results

i. Contingency Analysis Post-Contingency Transmission Equipment Loading

The only post-contingency equipment overload found was on the 230/345 kV transformer at the Hilltop Substation. The transformer's normal and emergency ratings are set at 300 MVA in the WECC HS2 base case. The highest loading of 330 MVA is 110% of the emergency rating normally applied after an N-1 contingency.

REPLACEMENT SCENARIOS FOR NVPP AND TSPP GENERATION
EQUIPMENT OVERLOADS (>100% emergency rating)

Transmission Facility	Imports From Ajacent Areas		Imports from Arizona		Imports from Oregon/Idaho		Increases in In-State Energy Efficiency & Distributed Generation	
	# of Violating Contingencies	Worst Value	# of Violating Contingencies	Worst Value	# of Violating Contingencies	Worst Value	# of Violating Contingencies	Worst Value
HIL TOP (40537) -> HIL TOP (64058) CKT 1 at HIL TOP					23	330.53		

Figure 4 - Ctriteria Violations - Equipment Overloads

The post-contingency loading on this transformer only triggers a violation for the "Imports for Oregon/Idaho" replacement scenario.

An investigation into factors that determine this transformer's ratings would need to be undertaken to identify possible mitigations. One option is to examine if a bottleneck exists on the transformer equipment (e.g. bushing limits) that prevent the contingency rating from being consistent with the Bordertown phase shifting transformer.

ii. Post-Contingency High Voltage Levels

Some high post-contingency bus voltages are experienced for all replacement scenarios in the Fort Sage and Hilltop area.

The number of high bus voltage violations is highest for the "Imports from Oregon/Idaho" replacement scenario, as the percentages are over the 110% limit. These high voltage problems are at least partially a result of unresolved issues related to operation of the Alturus line, and therefore not necessarily atrributable to the "Imports from Oregon/Idaho" replacement scenario.

REPLACEMENT SCENARIOS FOR NVPP AND TSPP GENERATION
HIGH BUS VOLTAGES (>110% of nominal voltage)

Transmission Facility	Imports From Ajacent Areas		Imports from Arizona		Imports from Oregon/Idaho		Increases in In-State Energy Efficiency & Distributed Generation	
	# of Violating Contingencies	Worst Value	# of Violating Contingencies	Worst Value	# of Violating Contingencies	Worst Value	# of Violating Contingencies	Worst Value
ALTURAS (45007)					3	129.1%		
CANBY (40169)					4	123.5%		
CANBYTAP (40171)					4	123.4%		
CEDRVL T (40193)					3	127.7%		
DAVIS CR (40333)			2	110.2%	5	129.9%	2	110.1%
FISHHOLE (45105)					4	116.9%		
FT SAGE (64900)	2	114.2%	2	110.4%	3	135.8%	2	110.2%
FTSAGEPS (64901)	2	114.2%	2	110.4%	4	135.7%	2	110.2%
HIL TOP (40537)					5	129.6%		
HIL TOP (64058)	2	111.1%			4	129.4%		
MILE HI (45203)					4	123.2%		
ROBINSON (64895)	6	114.5%			2	110.1%	2	110.8%
RSHASC1 (18896)	6	114.5%			2	110.1%	2	110.8%
WARNER (41135)					5	129.5%		
WARNER (41136)					3	129.1%		

Figure 5 - Ctriteria Violations - High Bus Voltages

iii. <u>Post-Contingency Low Voltage Levels</u>

Low post-contingency voltages following loss of the Falcon to Robinson 345 kV line are experienced at seventeen buses in nothern Neveda for the "Imports from

REPLACEMENT SCENARIOS FOR NVPP AND TSPP GENERATION
LOW BUS VOLTAGES (<90% of nominal voltage)

Transmission Facility	Imports From Ajacent Areas		Imports from Arizona		Imports from Oregon/Idaho		Increases in In-State Energy Efficiency & Distributed Generation	
	# of Violating Contingencies	Worst Value	# of Violating Contingencies	Worst Value	# of Violating Contingencies	Worst Value	# of Violating Contingencies	Worst Value
BELKNAP (45373)					1	87.5%		
CROSSROADS (64655)			1	88.8%				
CRTZ FCAN T (64384)			1	89.2%				
CRTZ FCANYON (64383)			1	88.9%				
CRTZ HILLS (64382)			1	88.9%				
CRTZ PIPE (64175)			1	88.8%				
CRTZ S PIPE (64387)			1	88.8%				
GETCHELL (64291)			1	89.4%				
GUARDSHACK (64295)			1	89.1%				
HANSEN CRK T (64202)			1	89.8%				
HANSEN PIT (64302)			1	89.8%				
JUNIPER T (64292)			1	89.0%				
OXYGEN PLANT (64284)			1	88.9%				
PINION (64289)			1	89.0%				
PINION T (64288)			1	89.0%				
SAGEMILL (64286)			1	88.9%				
SHOVEL SUB (64290)			1	88.9%				
TURQ RIDGE (64293)			1	89.8%				

Figure 6 - Ctriteria Violations - Low Bus Voltages

Arizona" replacement scenario. Post-contingency bus voltages following loss of the Faclon to Robinson 345 kV line are also somewhat low at these same buses for the two other Import replacement scenarios, but still above the 90% threshold.

iv. Post-Contingency Voltage Change

All three import replacement scenarios experienced bus voltage decreases of greater than 8% at the Muller, Round Hill, and Stateline Substations for loss of the Buckeye to Muller 120 kV line.

REPLACEMENT SCENARIOS FOR NVPP AND TSPP GENERATION
LARGE VOLTAGE DECREASES (>8% of pre-contingency value)

Transmission Facility	Imports From Ajacent Areas		Imports from Arizona		Imports from Oregon/Idaho		Increases in In-State Energy Efficiency & Distributed Generation	
	# of Violating Contingencies	Worst Value	# of Violating Contingencies	Worst Value	# of Violating Contingencies	Worst Value	# of Violating Contingencies	Worst Value
MULLER (640005)	1	12.9%	1	12.9%	1	13.2%		
RND HILL (64092)	1	12.4%	1	12.3%	1	12.6%		
STATELIN (64102)	1	12.0%	1	12.0%	1	12.2%		

Figure 7 - Ctriteria Violations - Large Voltage Decreases

B. Transient Stability Analysis

Loss of the Falcon to Robinson 345 kV line is one of the more severe N-1 contingencies for all four of the studied generation replacement scenarios and was, therefore, selected for use in the transient stability analysis. The review of the transient bus voltage swings did not identify any violations to the WECC criterion for any of the four generation replacement scenarios. Proximity to violations was also screened with limits reduced to 50%, but still no issues were flagged. Transient stability simulations were expanded to faults on the Valmy-Falcon 345kV line and the Bordertown phase shifting transformer for the distributed replacement from adjacent areas scenario, but no issues were flagged.

C. Voltage Stability Analysis

Voltage stability simulations on the most severe scenario (replacement from Arizona) and contingency (Falcon-Robinson 345kV line) showed displacement of an additional 160 MW of area generation at Tracy can occur before the voltage stability limit is reached. For the specific condition studied, this represents an adequate power margin of 17.6% on the heavily impacted Falcon-Robinson 345kV line. The minimum requirement is 5%. Other conditions not studied could show less margin. Closer proximity to a voltage stability limit than found in this study could influence the nature and sizing of needed mitigations.

7. Mitigation Options

Each of the studied generation replacement scenarios stresses the transmission system in northern Nevada differently, however there are three general issues:

- High post-contingency bus voltages in the area around Hilltop.
- Low post-contingency bus voltages in the area around Falcon.
- High post-contingency bus voltage changes in the area around Muller.

Each of these issues can be mitigated by making small changes to the transmission system. There are many viable approaches available, and some will fit better than others into a coordinated plan for long-range transmission system expansion. What is described here are just examples of what might be done to mitigate each of the voltage issues described above:

- Install 100 Mvars of additional shunt reactors at Hilltop 230kV with post-contingency switching to lower post-contingency bus voltages.
- Install a 30 Mvar shunt capacitor bank at Falcon 120kV with post-contingency switching to raise post-contingency bus voltages.
- Install a second 12 Mvar shunt capacitor bank at Stateline with post-contingency switching to reduce the change in bus voltages.

These mitigation examples do not address the transformer overload for the "Imports from Oregon/Idaho" generation replacement option.

8. Study Results with the Example Mitigations

Falcon 120kV 30Mvar shunt capacitor: this option raises the most severe low voltage bus (Crossroads 120kV) with the most severe contingency (Robinson-Falcon 345kV) from 0.8883 to 0.9148.

Stateline 120kV second 12Mvar shunt capacitor: this option raises the most severe low voltage and deltaV violation bus (Muller 120kV) with the most severe contingency (Buckeye-Muller 120kV) from 0.8625 per unit and 12.9% deltaV to 0.9341 per unit and 5.674% deltaV.

Hilltop 230kV shunt reactor additions: this option changes the most severe over voltage bus (Ft Sage) with the most severe contingency (Bordertown 345kV phase shifting transformer) from 1.358 per unit to 1.0866.

9. Estimated Cost for Implementing the Example Mitigations

WECC published a report on "Capital Costs for Transmission and Substations" in February, 2014 that provides generic cost estimates for a wide range of transmission system facilities and equipment.

The WECC report includes an estimate of $20,700/Mvar for a shunt reactor. Assuming a 2%/year escalation in costs, the estimate rises to $21,536/Mvar (2016 dollars).

Using this estimate, the estimated cost for the 100 Mvar shunt reactors at Hilltop is $2,163,600 (2016 dollars).

The WECC report includes an estimate of $88,000/MVar for a static var compensators (SVC). Assuming a 2%/year escalation in costs, the estimate rises to $91,555/Mvar. Unfortunately, the WECC report does not include an estimate for the simpler mechanically switched shunt capacitor bank (MSC). Reliable pricing information is not publicly available, but we estimate that the cost of an MSC should be approximately one third of the cost for a comparably sized SVC. On this basis, the cost of an MSC is estimated to be $30,500/Mvar (2016 dollars).

Using this estimate, the estimated cost for the 30 Mvar capacitor bank at Fallon is $915,000 (2016 dollars) and the cost for the 12 Mvar capacitor bank at Stateline is $366,000 (2016 dollars).

The costs to implement automated switching of the existing shunt reactor at Hilltop should be in the rangle of $250,000 (2016 dollars).

It should be noted that these estimates are subject to high margins of error as we do not have information regarding what are included in these generic cost estimates and/or what additional costs may need to be applied (e.g. substation land costs, bus extension costs). The accuracy of preliminary cost estimates such as these can be high or low by as much as 50%. Bearing this in mind, the cost of implementing these example mitigations for the conditions studied can be preliminarily estimated at between $1.8M and $5.5M (2016 dollars).

Attachment A
WECC TPL-001-WECC-CRT-3

A. Introduction

1. **Title:** **Transmission System Planning Performance**
2. **Number:** TPL-001-WECC-CRT-3
3. **Purpose:** To facilitate coordinated near-term and long-term transmission planning within the Interconnection of the Western Electricity Coordinating Council (WECC), and to facilitate the exchange of the associated planning information for normal and abnormal conditions.

   This document applies to all transmission planning studies conducted within the Interconnection of the Western Electricity Coordinating Council (WECC).

   This is a planning criterion. This document does not designate the entity responsible for system remediation.[2]

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Transmission Planner

   4.2. Facilities

   4.2.1. This document applies to Bulk Electric System (BES) Facilities.

   4.2.2. The following buses are specifically *excluded* from this WECC Criterion:

   4.2.2.1. Non-BES buses

   4.2.2.2. Line side series capacitor buses

   4.2.2.3. Line side series reactor buses

   4.2.2.4. Dedicated shunt capacitor buses

   4.2.2.5. Dedicated shunt reactor buses

   4.2.2.6. Metering buses, fictitious buses, or other buses that model point of interconnection solely for measuring electrical quantizes; and,

   4.2.2.7. Other buses specifically excluded by each Planning Coordinator or Transmission Planner internal to their system

5. **Effective Date:** The Effective Date is the later of January 1, 2016 or the Effective Date of TPL-001-4, Transmission System Planning Performance, Requirements R2-R6 and R8, subject to approvals.

[2] TPL-001-WECC-2.1, System Performance, WECC's Disturbance Performance Table (Table W-1) of Allowable Effects Other System (Table) was retired by the WECC Ballot Body on October 8, 2015 with WECC Board of Director approval on December 5, 2013.

B.Requirements and Measures

WR1. 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 P0[3] event (system normal pre-contingency event powerflow);

1.1.2. 90 percent to 110 percent of nominal for P1-P7[4] events (post-contingency event powerflow).

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

1.3. 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.

1.4. 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.

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% of pre-contingency voltage for more than 30 cycles nor remain below 80% 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.

WM1. Each Transmission Planner and Planning Coordinator will have evidence that it used the base criteria in its Planning Assessment specified in Requirement WR1, unless otherwise allowed in accordance with Requirements WR2 and WR3.

WR2. Each Transmission Planner and Planning Coordinator that uses a more stringent criterion than that stated in Requirement WR1 shall apply that criterion only to its own system, except where otherwise agreed upon by all other planning entities to which the more stringent criterion was applied.

[3] P0 through P7 refers to the categories of contingencies identified in Table 1 of NERC Standard TPL-001-4, Transmission System Planning Performance Requirements.

[4] Previously cited

WM2. Each Transmission Planner and Planning Coordinator that uses a more stringent criterion in its planning assessment than that stated in Requirement WR1 and applied that criterion to other systems will have evidence of agreement from all other planning entities to which the more stringent criteria was applied.

WR3. Each Transmission Planner and Planning Coordinator that uses a less stringent criterion than that stated in Requirement WR1 shall allow other Transmission Planners and Planner Coordinators to have the same impact on that part of the system for the same category of planning events (e.g., P1, P2).

WM3. Each Transmission Planner and Planning Coordinator that uses a less stringent criterion than that stated in Requirement WR1 will have evidenced that it allowed other Transmission Planners and Planner Coordinators to have the same impact on that part of the system for the same category of planning events (e.g., P1, P2).

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

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

WM4. Each Transmission Planner and Planning Coordinator will have evidence that it used the indicators of Requirement WR4 to identify the potential for Cascading or uncontrolled islanding.

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.

WM5. Each Transmission Planner and Planning Coordinator will have evidenced that it used the minimum criteria identified in Requirement WR5 to identify voltage stability.

WR6. Each Transmission Planner and Planning Coordinator that uses study criteria different from the base criteria in Requirement WR1 shall make its criteria available upon request within 30 days.

WM6. Each Transmission Planner and Planning Coordinator that uses study criteria different from the base criteria in Requirement WR1 will have evidence that it made its criteria available upon request, as required in Requirement WR6.

Version History

1	March 6, 2008	WECC Planning Coordination Committee (PCC) approved TPL-(001 thru 004)-WECC-1-CR.	Reliability Subcommittee translates existing WECC components of NERC/WECC Planning Standards into a CRT.
1	April 16, 2008	WECC Board of Directors (Board) approved	No substantive changes
2	October 13, 2011	PCC approves	Clarifies "corridor"
2	December 1, 2011	Board approves	No substantive change
2	September 5, 2012	WECC Board of Directors changed designation	Approved a nomenclature change from "CRT" to "RBP"
2.1	August 6, 2013	Errata	WM2 Measure moved to WM3. WM3 Measure moved to WM4. WM4 Measure moved to WM2.
2.1	December 5, 2013	Board approves	Developed as WECC-0100, on October 8, 2013, the Ballot Pool retired WR1, WR2, WR4 and WR5 of TPL-(012 through 014)-WECC-RBP-2 as of the Effective Date of NERC TPL-001-4. On December 5, 2013, the Board ratified that decision. Table W-1, WECC Disturbance-Performance Table of Allowable Effects on Other Systems, Table W-1 Notes, Figure W-1, and Footnotes 1-3 were retired along with their supporting WECC Requirements, WR1, WR2, and WR5. FERC Order 786, October 17, 2013, set various effective dates for TPL-001-4. The enforcement date is set at January 1, 2015.
2.1	June 25, 2014	WECC Board of Directors changed designation	Changed from regional Business Practice (RBP) to Criterion (CRT). No other changes.
2.2	January 14, 2016	Errata	Retired WECC Requirements WR1, WR2, WR4, and WR5 and their subsets were removed from the document. WR3 was renumbered to WR1.
3	Pending	WECC Board of Directors Approved	Further developed as WECC-0100, this document addresses the substance of its preceding version (2.2) and the requirements imposed by NERC TPL-001-4, Transmission System Planning Performance Requirements, Requirements R5 and R6. This project also addressed the substance of Table W-1 retired from its preceding version 2.1.

Disclaimer

WECC receives data used in its analyses from a wide variety of sources. WECC strives to source its data from reliable entities and undertakes reasonable efforts to validate the accuracy of the data used. WECC believes the data contained herein and used in its analyses is accurate and reliable. However, WECC disclaims any and all representations, guarantees, warranties, and liability for the information contained herein and any use thereof. Persons who use and rely on the information contained herein do so at their own risk.

Rationale

A Rationale section is optional. If Rationale Boxes were used during the development of this project, the content of those boxes appears below.

Rationale for Requirement WR1

This is a planning criterion.

WR1 addresses NERC TPL R5 and R6.

WR1 is designed to state the base planning criteria the system must meet – unless an individual entity or group of entities has different criteria. WECC Requirements WR2 and WR3 allow for entities to have different criteria.

Neither WR2 nor WR3 changes the WR1 default; rather, WR2 and WR3 allow for deviation from the WR1 default. WR2 allows for a more stringent approach without changing the WR1 default. A more stringent approach may be used in accordance with WR2 so long as all the affected parties agree. Similarly, WR3 allows deviation from the default with the additional protection that when used, other Transmission Planners and Planning Coordinators are allowed to use the same criteria on that part of the system for the same category of planning events (e.g., P1 and P2).

In the context of Requirement WR1, the word "nominal" carries its common definition and could be, for example, either the base voltage or the operating voltage as established in the entity's Planning Assessment. This means that nominal may have a varying definition or use from one entity to the next. If an entity does not specify what is nominal, the default use of the term nominal defaults to the kilo-volt class that is specified in the WECC Base Case, with the exception of the 500 kilo-vote class, in which case the default nominal would be specified as 525 kilo-volt.

Requirement WR1.1.2 refers to the post automatic equipment adjustment effect prior to manual adjustment.

Rationale for Requirement WR1.2

For purposes of this document, a BES bus that is serving load is the bus with direct transformation from BES-level voltage to distribution-level voltage that serves load.

In developing WR1.2, the drafting team was aware that eight percent is not the only practical percentage for use. Historically, stakeholders reported successfully using percentages between five and ten whereas others reported being under a regulatory mandate to use eight percent. To accommodate both positions the team selected the eight percent.

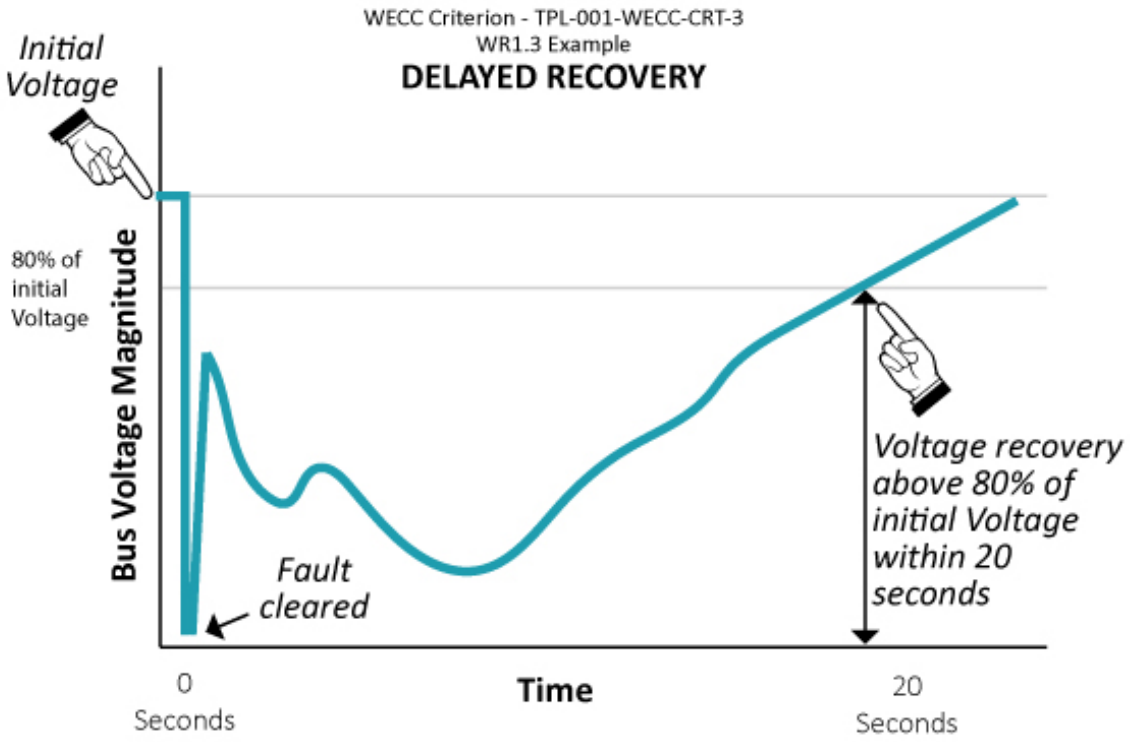
By default, only automatic post-contingency actions occurring in the studied timeframe are considered when calculating voltage deviation. This would include, among other things, capacitor or reactor switching. For purposes of WR1.2, automatic generally means a programmed response not manually initiated.

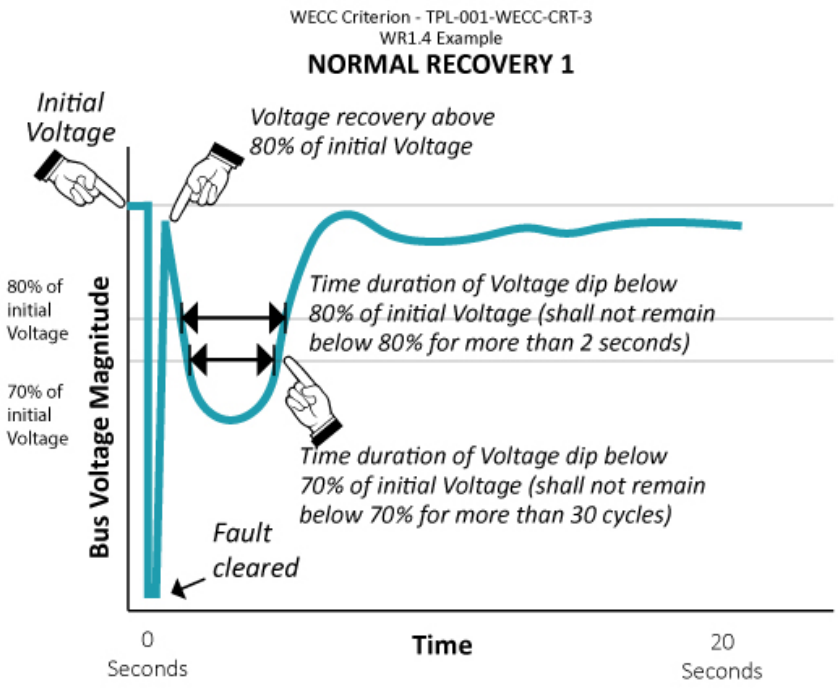
For P1 there is no high voltage deviation requirement. For P2-P7, there is no low or high voltage deviation requirement. It is implied that P2 through P7 events don't require a voltage deviation beyond meeting the requirements in WR1.1.2.

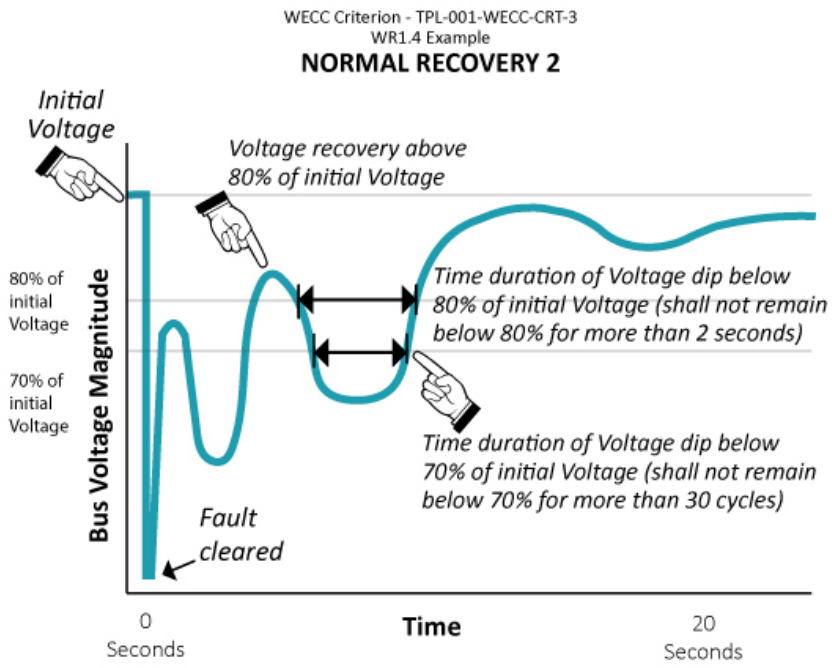
For purposes of this document, a BES bus that is serving load is the bus with direct transformation from BES-level voltage to distribution-level voltage that serves load.

The following illustrations apply to WR1.3 and WR1.4, and not WR1.2.

The following diagrams are offered for illustrative purposes. They are not designed to depict all possible voltage trajectories.




WECC Criterion - TPL-001-WECC-CRT-3
WR1.4 Example
NORMAL RECOVERY 1
Initial Voltage
Voltage recovery above 80% of initial Voltage
80% of initial Voltage
70% of initial Voltage
Bus Voltage Magnitude
Time duration of Voltage dip below 80% of initial Voltage (shall not remain below 80% for more than 2 seconds)
Time duration of Voltage dip below 70% of initial Voltage (shall not remain below 70% for more than 30 cycles)
Fault cleared
0 Seconds
Time
20 Seconds


WECC Criterion - TPL-001-WECC-CRT-3
WR1.4 Example
NORMAL RECOVERY 2
Initial Voltage
Voltage recovery above 80% of initial Voltage
80% of initial Voltage
70% of initial Voltage
Bus Voltage Magnitude
Time duration of Voltage dip below 80% of initial Voltage (shall not remain below 80% for more than 2 seconds)
Time duration of Voltage dip below 70% of initial Voltage (shall not remain below 70% for more than 30 cycles)
Fault cleared
0 Seconds
Time
20 Seconds

Rationale for Requirement WR1.5 and 1.6

For purposes of this document, a BES bus that is serving load is the bus with direct transformation from BES-level voltage to distribution-level voltage that serves load.

The intent is not to require that transient stability simulations be run out to 30-seconds in all cases in order to ensure the system is stable and positively damped. Shorter runs are permissible if it can be shown that applicable criteria can be met within a shorter time frame.

For purposes of Requirement WR1.6, positive damping in stability analysis is demonstrated by showing that the amplitude of power angle or voltage magnitude oscillations after a minimum of 10 seconds is less than the initial post-contingency amplitude. In any case, results that do not show positive damping within a 30-second time frame are considered to be undamped.

The 30-second window is a general reference and does not refer to any specific time window.

Rationale for Requirement WR2

Planning Assessment is a NERC defined term. As stated in the Purpose statement, this document applies to all transmission planning studies conducted within the Interconnection of the Western Electricity Coordinating Council (WECC).

The rationale for Requirement WR2 is to ensure that the planning entity does not impose more stringent requirements on systems other than their own. It may use more stringent criteria on its own system but may not impose more stringent criteria on others.

Transmission Planners and Planning Coordinators may mutually agree to use study criteria that is more stringent than that described in this document.

Rationale for Requirement WR3

The rationale is to ensure equity between planning entities. (Availability of differing criteria is addressed in Requirement WR6.)

Rationale for Requirement WR4

Requirement WR4 is designed to establish screening criteria that when exceeded may require further investigation of instability. The Requirement is not intended to show the presence of Cascading or instability. An entity is allowed to use these criteria for instability if they choose without imposing it on others.

The term Cascading in WR4 is the NERC defined term.

In WR4, Bullet 1, the 125% threshold is imported from the Peak RC System Operating Limits Methodology. The 125% threshold should only be used for facilities where the trip setting is not known. If the trip setting is known that known setting should be used. For example, if the known trip setting is 150% of the continuous rating, this should take precedence over the 125% of the highest rating.

The specific amounts of unrestrained load loss addressed in WR4, Bullet three, are not specified in this document. Because of the breadth of the possible permutations, the amount should be left to the sound engineering judgment of the planning entity.

Rationale for Requirement WR5

Requirement WR5 addresses "what" must be achieved and does not address "how" to do it.

For a review of "how" to achieve the goals, please refer to:

- The WECC Voltage Stability Assessment Methodology
- WECC Guide to WECC/NERC Planning Standards I.D: *Voltage Support and Reactive Power,* prepared by: Reactive Reserve Working Group (RRWG), Under the auspices of Technical Studies Subcommittee (TSS); Approved by TSS, March 30, 2006
- Additional guidance is contained in Section 2.2 Voltage Stability of the Guide to WECC/NERC Planning Standards 1.D, Voltage Support and reactive Power, March 30, 2006.

The intent of Requirement WR5 is to ensure the voltage stability of transfer paths as well as the system as a whole during peak load or peak transfer conditions. A margin on real power flow is used as a test for voltage stability. A positive reactive power margin can be demonstrated by a valid steady state power flow solution.

Power flow solutions refer to post contingency conditions where the actions of reactive devices and load tap changers should be modeled for the appropriate time frame being studied.

There is a higher likelihood of occurrence of a P0 to P1 category event; therefore, a higher margin (105%) is used. For P2-P7, there is a lower likelihood of occurrence; therefore, the lower margin (102.5%) is used.

Rationale for Requirement WR6

Requirement WR6 ensures the free flow of information between entities.