Report on

GEN-2017-094 Modification Request Impact Study

Revision R2 January 19, 2023

Submitted to
Southwest Power Pool

SPP Southwest Power Pool

anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
1/06/2023	Aneden Consulting	Initial Report Issued
1/19/2023	Aneden Consulting	Added WindFREE reactive power capability information

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2017-094, an active Generation Interconnection Request (GIR) with a Point of Interconnection (POI) on the Fort Thompson to Huron 230 kV line.

The GEN-2017-094 project interconnects in the Western Area Power Administration (WAPA), control area with a capacity of 200 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2017-094 to change the turbine configuration to 71 x GE 2.82 MW for a total capacity of 200.22 MW. This generating capacity for GEN-2017-094 (200.22 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 200 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. In addition, the modification request included changes to the collection system, generator step-up transformers, and main substation transformers. The existing and modified configurations for GEN-2017-094 are shown in Table ES-2.

Table ES-1: GEN-2017-094 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2017-094	Tap on Fort Thompson 230 kV (652507) to Huron 230 kV (652514) line (G17-094-TAP 589324)	80 x GE 2.5 MW = 200 MW	200

Table ES-2: GEN-2017-094 Modification Request

Facility	Existing Configuration		Modification Configuration
Point of Interconnection	Tap on Fort Thompson 230 kV (652507) to Huron 230 kV (652514) line (G17-094-TAP 589324)		Tap on Fort Thompson 230 kV (652507) to Huron 230 kV (652514) line (G17-094-TAP 589324)
Configuration/Capacity	80 x GE 2.5 MW = 200 MW		71 x GE 2.82 MW = 200.22 MW POI limited to 200 MW
Generation Interconnection Line	Length = 6.5 miles R = 0.001762 pu X = 0.009261 pu B = 0.017717 pu Rating MVA = 361.3 MVA		Length = 6.5 miles R = 0.001762 pu X = 0.009261 pu B = 0.017717 pu Rating MVA = 361.3 MVA
Main Substation Transformer[1]	X = 9.498%, R = 0.173%, Winding MVA = 66 MVA, Rating MVA = 110 MVA	X = 9.498%, R = 0.173%, Winding MVA = 66 MVA, Rating MVA = 110 MVA	X = 10.498%, R = 0.191%, Winding MVA = 127.2 MVA, Rating MVA = 212 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 40 X = 5.722%, R = 0.572%, Winding MVA = 112 MVA, Rating MVA = 112 MVA	Gen 2 Equivalent Qty: 40 X = 5.722%, R = 0.572%, Winding MVA = 112 MVA, Rating MVA = 112 MVA	Gen 1 Equivalent Qty: 71 X = 6.47%, R = 0.622%, Winding MVA = 230.75 MVA, Rating MVA[2] = 230.8 MVA
Equivalent Collector Line[3]	R = 0.014300 pu X = 0.018570 pu B = 0.041210 pu	R = 0.018010 pu X = 0.025340 pu B = 0.051750 pu	R = 0.004096 pu X = 0.007699 pu B = 0.096370 pu
Generator Dynamic Model[4] & Power Factor	40 x GE 2.5 MW (REGCA1)[4] Leading: 0.99 Lagging: 0.99	40 x GE 2.5 MW (GEWTGCU1)[4] Leading: 0.99 Lagging: 0.99	71 x GE 2.82 MW (GEWTG0705)[4] Leading: 0.87 Lagging: 0.87

1) X and R based on Winding MVA, 2) Rating rounded in PSS/E, 3) All pu are on 100 MVA Base, 4) DYR stability model name

SPP determined that power flow should not be performed based on the POI MW injection decrease of 1.11% compared to the DISIS-2017-002 power flow models (GEN-2017-094 dispatched to 100%). However, SPP determined that while the modification used the same turbine manufacturer, GE, the change in stability model from REGCA1 and GEWTGCU1 to GEWTG0705 required short circuit and dynamic stability analyses.

The scope of this modification request study included charging current compensation analysis, short circuit analysis, and dynamic stability analysis.

Aneden performed the analyses using the modification request data based on the DISIS-2017-002 study models:

1. 2025 Summer Peak (25SP),
2. 2025 Winter Peak (25WP)

All analyses were performed using the PTI PSS/E version 34 software and the results are summarized below.

The results of the charging current compensation analysis using the 2025 Summer Peak and 2025 Winter Peak models showed that the GEN-2017-094 project needed a 11.4 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 9.3 MVAr found in the DISIS-2017-001 study[1]. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The short circuit analysis was performed using the 25SP model. The results from the short circuit analysis with the updated topology showed that the maximum GEN-2017-094 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2017-094 POI was no greater than 1.17 kA. All three-phase fault current levels within 5 buses of the POI with the GEN-2017-094 generator online were below 38 kA.

The dynamic stability analysis was performed using PTI PSS/E version 34.8 software for the two modified study models: 2025 Summer Peak and 2025 Winter Peak. 79 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

The results of the dynamic stability analysis showed that oscillations were observed for several generation units including CENTER2G (657748), COYOTE1G (661015), and HESKET3G (661102) under multiple contingencies in the original DISIS-2017-002 case and the case with the GEN-2017-094 modification. These issues were not attributed to the GEN-2017-094 modification request.

There were no damping or voltage recovery violations attributed to the GEN-2017-094 modification request observed during the simulated faults. Additionally, the project was found to stay connected

[1] DISIS-2017-001-2 Restudy of Stability and Short Circuit Analysis – June 16, 2022

during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

The requested modification has been determined by SPP to not be a Material Modification. The requested modification does not have a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date. As the requested modification places the generating capacity of the Interconnection Request at a higher amount than its Interconnection Service, the customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

In accordance with FERC Order No. 827, the generating facility will be required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation.

It is likely that the customer may be required to reduce its generation output to 0 MW in real-time, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of transmission service or delivery rights. If the customer wishes to obtain deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the customer.

1.0 Scope of Study

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2017-094. A Modification Request Impact Study is a generation interconnection study performed to evaluate the impacts of modifying the DISIS study assumptions. The determination of the required scope of the study is dependent upon the specific modification requested and how it may impact the results of the DISIS study. Impacting the DISIS results could potentially affect the cost or timing of any Interconnection Request with a later Queue priority date, deeming the requested modification a Material Modification. The criteria sections below include reasoning as to why an analysis was either included or excluded from the scope of study.

All analyses were performed using the PTI PSS/E version 34 software. The results of each analysis are presented in the following sections.

1.1 Power Flow Analysis

To determine whether power flow analysis is required, SPP evaluates the difference in the real power output at the POI between the DISIS-2017-002 power flow configuration and the requested modification. Power flow analysis is performed if the difference in the real power may result in a significant impact on the results of the DISIS power flow analysis.

1.2 Stability Analysis, Short Circuit Analysis

To determine whether stability and short circuit analyses are required, SPP evaluates the difference between the turbine parameters and, if needed, the equivalent collector system impedance between the existing configuration and the requested modification. Dynamic stability analysis and short circuit analysis would be required if the differences listed above were determined to have a significant impact on the most recently performed DISIS stability analysis.

1.3 Charging Current Compensation Analysis

SPP requires that a charging current compensation analysis be performed on the requested modification configuration as it is a non-synchronous resource. The charging current compensation analysis determines the capacitive effect at the POI caused by the project's collector system and transmission line's capacitance. A shunt reactor size is determined in order to offset the capacitive effect and maintain zero (0) MVAr flow at the POI while the project's generators and capacitors are offline.

1.4 Study Limitations

The assessments and conclusions provided in this report are based on assumptions and information provided to Aneden by others. While the assumptions and information provided may be appropriate for the purposes of this report, Aneden does not guarantee that those conditions assumed will occur. In addition, Aneden did not independently verify the accuracy or completeness of the information provided. As such, the conclusions and results presented in this report may vary depending on the extent to which actual future conditions differ from the assumptions made or information used herein.

2.0 Project and Modification Request

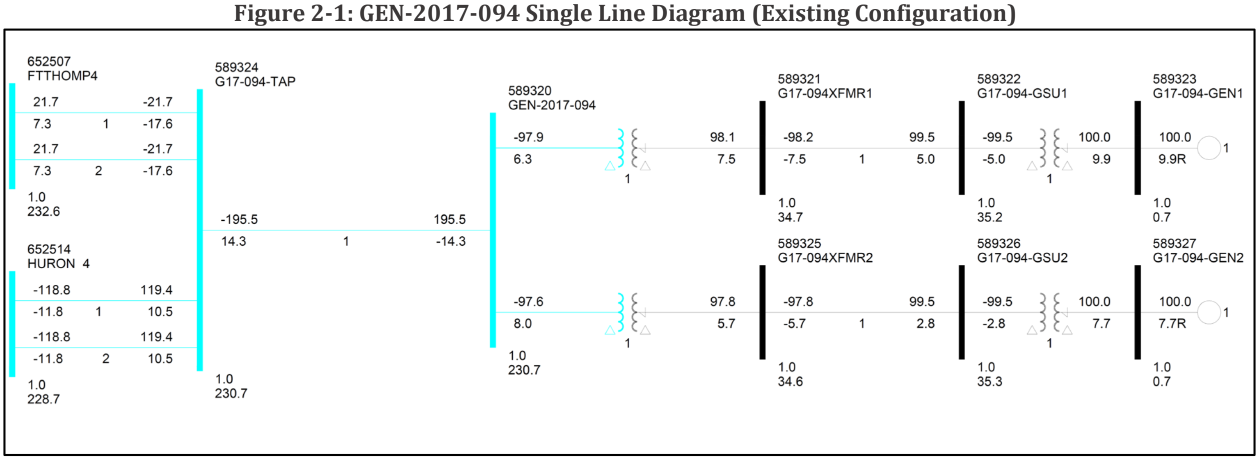
The GEN-2017-094 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a Point of Interconnection (POI) on the Fort Thompson to Huron 230 kV line. At the time of report posting, GEN-2017-094 is an active Interconnection Request with a queue status of "IA FULLY EXECUTED/ON SCHEDULE." GEN-2017-094 is a wind farm with a maximum summer and winter queue capacity of 200 MW with Energy Resource Interconnection Service (ERIS).

The GEN-2017-094 project is currently in the DISIS-2017-001 cluster. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2017-094 configuration. The GEN-2017-094 project interconnects in the Western Area Power Administration (WAPA) control area with a capacity of 200 MW as shown in Table 2-1 below.

Table 2-1: GEN-2017-094 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2017-094	Tap on Fort Thompson 230 kV (652507) to Huron 230 kV (652514) line (G17-094-TAP 589324)	80 x GE 2.5 MW = 200 MW	200

Figure 2-1: GEN-2017-094 Single Line Diagram (Existing Configuration)



This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2017-094 to a turbine configuration of 71 x GE 2.82 MW for a total capacity of 200.22 MW. This generating capacity for GEN-2017-094 (200.22 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 200 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

In addition, the modification request included changes to the collection system, generator step-up transformers, and main substation transformers. Figure 2-2 shows the power flow model single line diagram for the GEN-2017-094 modification. The existing and modified configurations for GEN-2017-094 are shown in Table 2-2.

Figure 2-2: GEN-2017-094 Single Line Diagram (Modification Configuration)

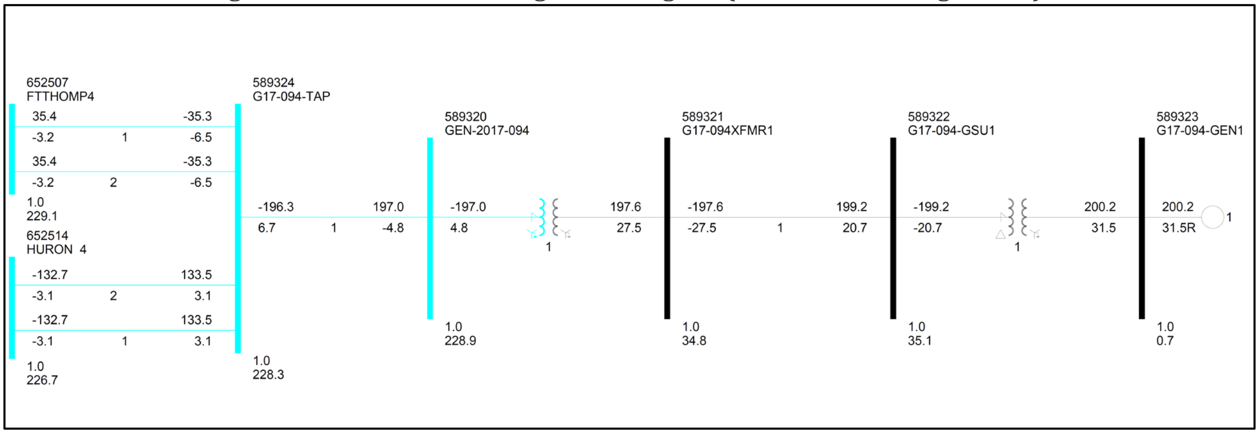


Table 2-2: GEN-2017-094 Modification Request

Facility	Existing Configuration		Modification Configuration
Point of Interconnection	Tap on Fort Thompson 230 kV (652507) to Huron 230 kV (652514) line (G17-094-TAP 589324)		Tap on Fort Thompson 230 kV (652507) to Huron 230 kV (652514) line (G17-094-TAP 589324)
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Generation Interconnection Line	Length = 6.5 miles R = 0.001762 pu X = 0.009261 pu B = 0.017717 pu Rating MVA = 361.3 MVA		Length = 6.5 miles R = 0.001762 pu X = 0.009261 pu B = 0.017717 pu Rating MVA = 361.3 MVA
Main Substation Transformer[1]	X = 9.498%, R = 0.173%, Winding MVA = 66 MVA, Rating MVA = 110 MVA	X = 9.498%, R = 0.173%, Winding MVA = 66 MVA, Rating MVA = 110 MVA	X = 10.498%, R = 0.191%, Winding MVA = 127.2 MVA, Rating MVA = 212 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 40 X = 5.722%, R = 0.572%, Winding MVA = 112 MVA, Rating MVA = 112 MVA	Gen 2 Equivalent Qty: 40 X = 5.722%, R = 0.572%, Winding MVA = 112 MVA, Rating MVA = 112 MVA	Gen 1 Equivalent Qty: 71 X = 6.47%, R = 0.622%, Winding MVA = 230.75 MVA, Rating MVA[2] = 230.8 MVA
Equivalent Collector Line[3]	R = 0.014300 pu X = 0.018570 pu B = 0.041210 pu	R = 0.018010 pu X = 0.025340 pu B = 0.051750 pu	R = 0.004096 pu X = 0.007699 pu B = 0.096370 pu
Generator Dynamic Model[4] & Power Factor	40 x GE 2.5 MW (REGCA1)[4] Leading: 0.99 Lagging: 0.99	40 x GE 2.5 MW (GEWTGCU1)[4] Leading: 0.99 Lagging: 0.99	71 x GE 2.82 MW (GEWTG0705)[4] Leading: 0.87 Lagging: 0.87

1) X and R based on Winding MVA, 2) Rating rounded in PSS/E, 3) All pu are on 100 MVA Base, 4) DYR stability model name

3.0 Existing vs Modification Comparison

To determine which analyses are required for the Study, the differences between the existing configuration and the requested modification were evaluated. Aneden performed this comparison and the resulting analyses using a set of modified study models developed based on the modification request data and the DISIS-2017-002 study models.

The methodology and results of the comparisons are described below. The analysis was completed using PSS/E version 34 software.

3.1 POI Injection Comparison

The real power injection at the POI was determined using PSS/E to compare the DISIS-2017-002 power flow configuration and the requested modifications for GEN-2017-094. The percentage change in the POI injection was then evaluated. If the MW difference was determined to be significant, power flow analysis would be performed to assess the impact of the modification request.

SPP determined that power flow analysis was not required due to the insignificant change (decrease of 1.11%) in the real power output at the POI between the studied DISIS-2017-002 power flow configuration (GEN-2017-094[2] dispatched to 100%) and requested modification shown in Table 3-1.

Table 3-1: GEN-2017-094 POI Injection Comparison

Interconnection Request	Existing POI Injection (MW)	Modification POI Injection (MW)	POI Injection Difference %
GEN-2017-094	198.5	196.3	-1.11%

3.2 Turbine Parameters Comparison

SPP determined that while the modification used the same turbine manufacturer, GE, the change in stability model from REGCA1 and GEWTGCU1 to GEWTG0705 required short circuit and dynamic stability analysis. This is because the short circuit contribution and stability responses of the existing configuration and the requested modification's configuration may differ. The generator dynamic model for the modification can be found in Appendix A.

As short circuit and dynamic stability analyses were required, a turbine parameters comparison was not needed for the determination of the scope of the study.

3.3 Equivalent Impedance Comparison Calculation

As the turbine stability model change determined that short circuit and dynamic stability analyses were required, an equivalent impedance comparison was not needed for the determination of the scope of the study.

[2] Note that the project was not dispatched to 100% in the starting models due the SPP fuel based dispatch

4.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2017-094 to determine the capacitive charging effects during reduced generation conditions (unsuitable wind speeds, unsuitable solar irradiance, insufficient state of charge, idle conditions, curtailment, etc.) at the generation site and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

4.1 Methodology and Criteria

The GEN-2017-094 generators were switched out of service while other system elements remained in-service. A shunt reactor was tested at the project's collection substation 34.5 kV bus to set the MVAr flow into the POI to approximately zero. The size of the shunt reactor is equivalent to the charging current value at unity voltage and the compensation provided is proportional to the voltage effects on the charging current (i.e., for voltages above unity, reactive compensation is greater than the size of the reactor).

Aneden performed the charging current compensation analysis using the modification request data based on the DISIS-2017-002 stability study models:

1. 2025 Summer Peak (25SP),
2. 2025 Winter Peak (25WP)

4.2 Results

The results from the analysis showed that the GEN-2017-094 project needed approximately 11.4 MVAr of compensation at its project substation to reduce the POI MVAr to zero. This is an increase from the 9.3 MVAr found in the DISIS-2017-001 study[3]. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the updated topology. The final shunt reactor requirements for GEN-2017-094 are shown in Table 4-1.

The GE turbines used in the GEN-2017-094 project configuration have WindFREE[4] reactive power capability that may exceed the reactor size requirements calculated in this analysis. This reactive power capability should be further discussed between the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator.

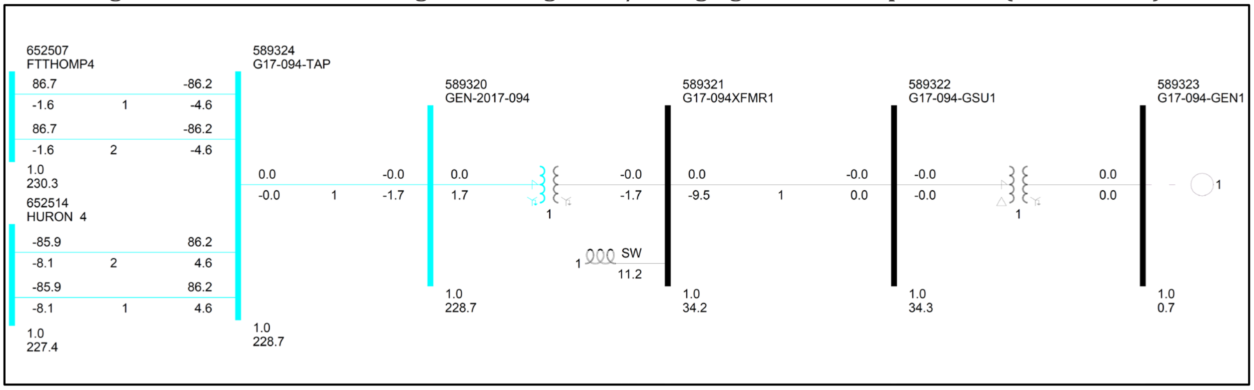
The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

Table 4-1: Shunt Reactor Size for Low Wind Study (Modification)

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)	
			25SP	25WP
GEN-2017-094	589324	G17-094-TAP 230 kV	11.4	11.4

[3] DISIS-2017-001-2 Restudy of Stability and Short Circuit Analysis – June 16, 2022
[4] Technical Documentation Wind Turbine Generator Systems 2MW Platform - 60 Hz Rev. 07 – February 12, 2021

Figure 4-1: GEN-2017-094 Single Line Diagram w/ Charging Current Compensation (Modification)



5.0 Short Circuit Analysis

A short circuit study was performed using the 25SP model for GEN-2017-094. The detailed results of the short circuit analysis are provided in Appendix B.

5.1 Methodology

The short circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 230 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels in the transmission system with and without GEN-2017-094 online.

Aneden created a short circuit model using the 2025 Summer Peak DISIS-2017-002 stability study model by adjusting the GEN-2017-094 short circuit parameters consistent with the modification data. The adjusted parameters are shown in Table 5-1 below.

Table 5-1: Short Circuit Model Parameters

Parameter	Value by Generator Bus#
	589323
MVA Base	230.11
R (pu)	0.0
X'' (pu)	0.2

5.2 Results

The results of the short circuit analysis for the 25SP model are summarized in Table 5-2 and Table 5-3. The GEN-2017-094 POI bus (G17-094-TAP 230 kV - 589324) fault current magnitudes are provided in Table 5-2 showing a maximum fault current of 11.35 kA with the GEN-2017-094 project online.

The maximum fault current calculated within 5 buses of the GEN-2017-094 POI (including the POI bus) was less than 38 kA for the 25SP model. The maximum GEN-2017-094 contribution to three-phase fault current was about 11.5% and 1.17 kA.

Table 5-2: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
25SP	10.18	11.35	1.17	11.5%

Table 5-3: 25SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	18.2	0.03	0.4%
115	37.0	0.38	2.6%
161	20.2	0.00	0.0%
230	19.9	1.17	11.5%
345	18.5	0.12	2.6%
Max	**37.0**	**1.17**	**11.5%**

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine configuration change and other modifications to GEN-2017-094. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix C. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix A. The simulation plots can be found in Appendix D.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested GEN-2017-094 configuration of 71 x GE 2.82 MW (GEWTG0705). This stability analysis was performed using PTI's PSS/E version 34.8 software.

The modifications requested for the GEN-2017-094 project were used to create modified stability model**s** for this impact study based on the DISIS-2017-002 stability study models:

1. 2025 Summer Peak (25SP),
2. 2025 Winter Peak (25WP)

The modified dynamic model data for the GEN-2017-094 project is provided in Appendix A. The modified power flow models and associated dynamic database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data.

The following system adjustments were made to address existing base case issues that are not attributed to the modification request:

1. The Fort Thompson (652807), Grand Prairie (652833), LO.LS-FT-BE3 (659424) and CC.LS-LO-BE3 (659428) 345 kV in-line reactors were switched off in the peak load scenarios to avoid unrealistic low voltage issues.
2. The voltage protection relays were disabled on buses 645065 & 645067 (Grand Prairie), 762241 (GEN-2017-175), 588593 & 588597 (GEN-2017-014), and 635332 (NEWHRVST).

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2017-094 and other current and prior queued projects in their cluster group[5]. In addition, voltages of five (5) buses away from the POI of GEN-2017-094 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 356 (AMMO), 600 (XEL), 608 (MP), 615 (GRE), 620 (OTP), 627 (ALTW), 635 (MEC), 652 (WAPA), 659 (BEPC-SPP), 661 (MDU), and 680 (DPC) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

6.2 Fault Definitions

Aneden simulated the faults previously simulated for GEN-2017-094 and developed additional fault events as required. The new set of faults were simulated using the modified study models. The fault events included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults. Single-line-to-ground faults are approximated by applying a fault impedance to bring the faulted bus positive sequence voltage to 0.6 p.u. The simulated faults

[5] Based on the DISIS-2017-001 Cluster Groups

are listed and described in Table 6-1 below. These contingencies were applied to the modified 2025 Summer Peak and the 2025 Winter Peak models.

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT01-3PH	P1	3 phase fault on the FR E 230 kV (652509) / 115 kV (652510) XFMR CKT 1, near FTRANDL4 (652509) 230 kV. a. Apply fault at the FTRANDL4 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT02-3PH	P1	3 phase fault on the FTTHOMP4 (652507) to OAHE 4 (652519) 230 kV line CKT 2, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT05-3PH	P1	3 phase fault on the FTTHOMP4 (652507) to BIGBND14 (652540) 230 kV line CKT 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. **Trip generator BGBND12G (652542), BGBND34G (652543).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT06-3PH	P1	3 phase fault on the FTTHOMP4 (652507) to WESSINGTON 4 (652607) 230 kV line CKT 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT07-3PH	P1	3 phase fault on the FTTHOMP4 (652507) to LETCHER4 (652606) 230 kV line CKT 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT08-3PH	P1	3 phase fault on the FTTHOMP4 (652507) to FTRANDL4 (652509) 230 kV line CKT 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT11-3PH	P1	3 phase fault on the FTTHOMP4 (652507) to BIGBND24 (652541) 230 kV line CKT 2, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. **Trip generator BGBND56G (652544), BGBND78G (652545).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT28-3PH	P1	3 phase fault on the FTRANDL4 (652509) to SIOUXCY4 (652565) 230 kV line CKT 1, near FTRANDL4. a. Apply fault at the FTRANDL4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT42-3PH	P1	3 phase fault on the FTTHOMP4 (652507) to LAKPLAT-ER4 (655475) 230 kV line CKT 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT59-3PH	P1	3 phase fault on the WATERTN-LNX3 (652829) to WATERTN3 (652529) 345 kV line CKT Z, near WATERTN-LNX3. a. Apply fault at the WATERTN-LNX3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT64-3PH	P1	3 phase fault on the FTTHOMP3 (652506) to FTTHOM2-LNX3 (652807) to GRPRAR2-LNX3 (652833) to GR PRAIRIE 3 (652532) 345 kV line CKT 1, near FTTHOMP3. a. Apply fault at the FTTHOMP3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT83-3PH	P1	3 phase fault on the WATERTN3 (652529) to G09_001IST (659165) 345 kV line CKT 1, near WATERTN3. a. Apply fault at the WATERTN3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT94-3PH	P1	3 phase fault on the MEADOWGROVE4 (640540) to FTRANDL4 (652509) 230 kV line CKT 1, near MEADOWGROVE4. a. Apply fault at the MEADOWGROVE4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT95-3PH	P1	3 phase fault on the FTRANDL4 (652509) to LAKPLAT-ER4 (655475) 230 kV line CKT 1, near FTRANDL4. a. Apply fault at the FTRANDL4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT96-3PH	P1	3 phase fault on the FTRANDL4 (652509) to UTICAJC4 (652526) 230 kV line CKT 1, near FTRANDL4. a. Apply fault at the FTRANDL4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT103-3PH	P1	3 phase fault on the G17-094-TAP (589324) to FTTHOMP4 (652507) 230 kV line CKT 1, near G17-094-TAP. a. Apply fault at the G17-094-TAP 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT104-3PH	P1	3 phase fault on the G17-094-TAP (589324) to HURON (652514) 230 kV line CKT 1, near G17-094-TAP. a. Apply fault at the G17-094-TAP 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT105-3PH	P1	3 phase fault on the G16-094-TAP (587764) to FTTHOMP4 (652507) 230 kV line CKT 1, near G16-094-TAP. a. Apply fault at the G16-094-TAP 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT130-3PH	P1	3 phase fault on the SIOUXFL4 (652523) to LETCHER4 (652606) 230 kV line CKT 1, near SIOUXFL4. a. Apply fault at the SIOUXFL4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT205-3PH	P1	3 phase fault on the FT2 KU1A 345 kV (652506) / 230 kV (652507)/ 13.8 kV (652273) XFMR CKT 1, near FTTHOMP3 (652506) 345 kV. a. Apply fault at the FTTHOMP3 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT206-3PH	P1	3 phase fault on the FT2 KU1A 345 kV (652506) / 230 kV (652507)/ 13.8 kV (652274) XFMR CKT 1, near FTTHOMP3 (652506) 345 kV. a. Apply fault at the FTTHOMP3 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT207-3PH	P1	3 phase fault on the FT KV1B 230 kV (652507) / 69 kV (652276)/ 13.8 kV (652277) XFMR CKT 1, near FTTHOMP4 (652507) 230 kV. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT214-3PH	P1	3 phase fault on the WT2 KU1A 345 kV (652529) / 230 kV (652530)/ 13.8 kV (652237) XFMR CKT 1, near WATERTN3 (652529) 345 kV. a. Apply fault at the WATERTN3 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT216-3PH	P1	3 phase fault on the LET KV3A 230 kV (652606) / 115 kV (652609)/ 13.2 kV (652608) XFMR CKT 1, near LETCHER4 (652606) 230 kV. a. Apply fault at the LETCHER4 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9001-3PH	P1	3 phase fault on the FTTHOMP4 (652507) to G16-094-TAP (587764) 230 kV line CKT 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on the FT2 KU1A 345 kV (652506) / 230 kV (652507)/ 13.8 kV (652273) XFMR CKT 1, near FTTHOMP4 (652507) 230 kV. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9003-3PH	P1	3 phase fault on the HURON 4 (652514) to WATERTN4 (652530) 230 kV line CKT 2, near HURON 4. a. Apply fault at the HURON 4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9004-3PH	P1	3 phase fault on the HURON 4 (652514) to CARPENTER 4 (652614) 230 kV line CKT 1, near HURON 4. a. Apply fault at the HURON 4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on the CARPENTER 4 (652614) to WATERTN4 (652530) 230 kV line CKT 1, near CARPENTER 4. a. Apply fault at the CARPENTER 4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9006-3PH	P1	3 phase fault on the CRP KV1A 230 kV (652614) / 69 kV (655499) XFMR CKT 1, near CARPENTER 4 (652614) 230 kV. a. Apply fault at the CARPENTER 4 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9007-3PH	P1	3 phase fault on the WATERTN4 (652530) to APPLEDORN 4 (652582) 230 kV line CKT 1, near WATERTN4. a. Apply fault at the WATERTN4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 phase fault on the WATERTN4 (652530) to BLAIR-ER4 (655465) 230 kV line CKT 1, near WATERTN4. a. Apply fault at the WATERTN4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9009-3PH	P1	3 phase fault on the WATERTN4 (652530) to WATERTNCAP 4 (652630) 230 kV line CKT 1, near WATERTN4. a. Apply fault at the WATERTN4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9010-3PH	P1	3 phase fault on the WT KV2A 230 kV (652530) / 115 kV (652531) / 13.2 (652239) XFMR CKT 1, near WATERTN4 (652530) 230 kV. a. Apply fault at the WATERTN4 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9011-3PH	P1	3 phase fault on the WT2 KU1A 345 kV (652529) / 230 kV (652530) / 13.8 (652237) XFMR CKT 1, near WATERTN4 (652530) 230 kV. a. Apply fault at the WATERTN4 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9012-3PH	P1	3 phase fault on the WT KV1A 230 kV (652530) / 20 kV (652539) XFMR CKT 1, near WATERTN4 (652530) 230 kV. a. Apply fault at the WATERTN4 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer. **Trip generator WATERSVC (652539)**
FLT9013-3PH	P1	3 phase fault on the WATERTN3 (652529) to WATERTN-LNX3 (652829) 345 kV line CKT Z, near WATERTN3. a. Apply fault at the WATERTN3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9014-3PH	P1	3 phase fault on the FTTHOMP3 (652506) to FTTHOM1-LNX3 (652806) to CHAPELLE-BE3 (659130) 345 kV line CKT 1, near FTTHOMP3. a. Apply fault at the FTTHOMP3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9015-3PH	P1	3 phase fault on the GR PRAIRIE 3 (652523) to GRPRAR1-LNX3 (652832) to HOLT.CO3 (640510) 345 kV line CKT 1, near GR PRAIRIE 3. a. Apply fault at the GR PRAIRIE 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9016-3PH	P1	3 phase fault on the CHAPELLE-BE3 (659130) to CC.LS-LO-BE3 (659428) to G17-114-TAP (760357) 345 kV line CKT 1, near CHAPELLE-BE3. a. Apply fault at the CHAPELLE-BE3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9017-3PH	P1	3 phase fault on the FTTHOMP3 (652506) to FTTHOM1-LNX5 (652808) to CHAPELLE-BE3 (659130) 345 kV line CKT 1, near FTTHOMP3. a. Apply fault at the FTTHOMP3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9018-3PH	P1	3 phase fault on the OAHE 4 (652519) to PHILIP_T-BE4 (659188) 230 kV line CKT 1, near OAHE 4. a. Apply fault at the OAHE 4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9019-3PH	P1	3 phase fault on the OAHE 4 (652519) to SULLYBT-ER4 (655487) 230 kV line CKT 1, near OAHE 4. a. Apply fault at the OAHE 4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9020-3PH	P1	3 phase fault on the AT2 230 kV (652519) / 115 kV (652520)/ 13.8 kV (652598) XFMR CKT 1, near OAHE 4 (652519) 230 kV. a. Apply fault at the OAHE 4 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9021-3PH	P1	3 phase fault on the OA NO.2 230 kV (652519) /13.8 kV (652556) XFMR CKT 1, near OAHE 4 (652519) 230 kV. a. Apply fault at the OAHE 4 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer. **Trip generator OAHE2-3G (652556).**
FLT9022-3PH	P1	3 phase fault on the G16-094-TAP (587764) to GEN-2016-094 (587760) 230 kV line CKT 1, near G16-094-TAP. a. Apply fault at the G16-094-TAP 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. **Trip generator G16-094-GEN1 (587763).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9023-3PH	P1	3 phase fault on the BROADLND-BE3 (659120) to BD.LS-AV-BE3 (659421) 345 kV line CKT Z, near BROADLND-BE3. a. Apply fault at the BROADLND-BE3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9024-3PH	P1	3 phase fault on the LETCHER4 (652606) to SIOUXFL4 (652523) 230 kV line CKT 1, near LETCHER4. a. Apply fault at the LETCHER4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9025-3PH	P1	3 phase fault on the WWC KV1A 230 kV (652607) /34.5 kV (662100) XFMR CKT 1, near WESSINGTON 4 (652607) 230 kV. a. Apply fault at the WESSINGTON 4 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9026-3PH	P1	3 phase fault on the WESSINGTON 4 (652607) to SD.PW1_-BE4 (659295) 230 kV line CKT 1, near WESSINGTON 4. a. Apply fault at the WESSINGTON 4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. **Trip generator WESSINGTON1W (659296)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9027-3PH	P1	3 phase fault on the WESSINGTON 4 (652607) to STORLA_BE4 (659122) 230 kV line CKT 1, near WESSINGTON 4. a. Apply fault at the WESSINGTON 4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9028-3PH	P1	3 phase fault on the FTRANDL4 (652509) to MEADOWGROVE4 (640540) 230 kV line CKT 1, near FTRANDL4. a. Apply fault at the FTRANDL4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9029-3PH	P1	3 phase fault on the HURON 4 (652514) to BROADLND-BE4 (659205) 230 kV line CKT 1, near HURON 4. a. Apply fault at the HURON 4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9030-3PH	P1	3 phase fault on the HU KV1A 230 kV (652514) / 115 kV (652515) / 13.3 (652281) XFMR CKT 1, near HURON 4 (652514) 230 kV. a. Apply fault at the HURON 4 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9031-3PH	P1	3 phase fault on the G17-114-TAP (760357) to LO.LS-FT-BE3 (659424) to LELAND_O-BE3 (659105) 345 kV line CKT 1, near G17-114-TAP. a. Apply fault at the G17-114-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT103-PO1	P6	**PRIOR OUTAGE of G17-094-TAP (589324) to FTTHOMP4 (652507) 230 kV line CKT 2;** 3 phase fault on the G17-094-TAP (589324) to FTTHOMP4 (652507) 230 kV line CKT 1, near G17-094-TAP. a. Apply fault at the G17-094-TAP 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9003-PO1	P6	**PRIOR OUTAGE of G17-094-TAP (589324) to FTTHOMP4 (652507) 230 kV line CKT 2;** 3 phase fault on the HURON 4 (652514) to WATERTN4 (652530) 230 kV line CKT 2, near HURON 4. a. Apply fault at the HURON 4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9004-PO1	P6	**PRIOR OUTAGE of G17-094-TAP (589324) to FTTHOMP4 (652507) 230 kV line CKT 2;** 3 phase fault on the HURON 4 (652514) to CARPENTER 4 (652614) 230 kV line CKT 1, near HURON 4. a. Apply fault at the HURON 4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9029-PO1	P6	**PRIOR OUTAGE of G17-094-TAP (589324) to FTTHOMP4 (652507) 230 kV line CKT 2;** 3 phase fault on the HURON 4 (652514) to BROADLND-BE4 (659205) 230 kV line CKT 1, near HURON 4. a. Apply fault at the HURON 4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9030-PO1	P6	**PRIOR OUTAGE of G17-094-TAP (589324) to FTTHOMP4 (652507) 230 kV line CKT 2;** 3 phase fault on the HU KV1A 230 kV (652514) / 115 kV (652515) / 13.3 (652281) XFMR CKT 1, near HURON 4 (652514) 230 kV. a. Apply fault at the HURON 4 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT104-PO2	P6	**PRIOR OUTAGE of G17-094-TAP (589324) to HURON (652514) 230 kV line CKT 2;** 3 phase fault on the G17-094-TAP (589324) to HURON (652514) 230 kV line CKT 1, near G17-094-TAP. a. Apply fault at the G17-094-TAP 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT02-PO2	P6	**PRIOR OUTAGE of G17-094-TAP (589324) to HURON (652514) 230 kV line CKT 2;** 3 phase fault on the FTTHOMP4 (652507) to OAHE 4 (652519) 230 kV line CKT 2, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT05-PO2	P6	**PRIOR OUTAGE of G17-094-TAP (589324) to HURON (652514) 230 kV line CKT 2;** 3 phase fault on the FTTHOMP4 (652507) to BIGBND14 (652540) 230 kV line CKT 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. **Trip generator BGBND12G (652542), BGBND34G (652543).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT06-PO2	P6	**PRIOR OUTAGE of G17-094-TAP (589324) to HURON (652514) 230 kV line CKT 2;** 3 phase fault on the FTTHOMP4 (652507) to WESSINGTON 4 (652607) 230 kV line CKT 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT07-PO2	P6	**PRIOR OUTAGE of G17-094-TAP (589324) to HURON (652514) 230 kV line CKT 2;** 3 phase fault on the FTTHOMP4 (652507) to LETCHER4 (652606) 230 kV line CKT 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT08-PO2	P6	**PRIOR OUTAGE of G17-094-TAP (589324) to HURON (652514) 230 kV line CKT 2;** 3 phase fault on the FTTHOMP4 (652507) to FTRANDL4 (652509) 230 kV line CKT 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT11-PO2	P6	**PRIOR OUTAGE of G17-094-TAP (589324) to HURON (652514) 230 kV line CKT 2;** 3 phase fault on the FTTHOMP4 (652507) to BIGBND24 (652541) 230 kV line CKT 2, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. **Trip generator BGBND56G (652544), BGBND78G (652545).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT42-PO2	P6	**PRIOR OUTAGE of G17-094-TAP (589324) to HURON (652514) 230 kV line CKT 2;** 3 phase fault on the FTTHOMP4 (652507) to LAKPLAT-ER4 (655475) 230 kV line CKT 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT207-PO2	P6	**PRIOR OUTAGE of G17-094-TAP (589324) to HURON (652514) 230 kV line CKT 2;** 3 phase fault on the FT KV1B 230 kV (652507) / 69 kV (652276)/ 13.8 kV (652277) XFMR CKT 1, near FTTHOMP4 (652507) 230 kV. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9001-PO2	P6	**PRIOR OUTAGE of G17-094-TAP (589324) to HURON (652514) 230 kV line CKT 2;** 3 phase fault on the FTTHOMP4 (652507) to G16-094-TAP (587764) 230 kV line CKT 1, near FTTHOMP4. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9002-PO2	P6	**PRIOR OUTAGE of G17-094-TAP (589324) to HURON (652514) 230 kV line CKT 2;** 3 phase fault on the FT2 KU1A 345 kV (652506) / 230 kV (652507)/ 13.8 kV (652273) XFMR CKT 1, near FTTHOMP4 (652507) 230 kV. a. Apply fault at the FTTHOMP4 230 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT1001-SB	P4	**Stuck Breaker on FTTHOMP4 (652507) 230 kV bus.** a. Apply single-phase fault at FTTHOMP4 (652507) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the FTTHOMP4 (652507) to G17-094-TAP (589324) 230 kV line CKT 1. d. Trip the FTTHOMP4 (652507) to G16-094-TAP (587764) 230 kV line CKT 1.
FLT1002-SB	P4	**Stuck Breaker on FTTHOMP4 (652507) 230 kV bus.** a. Apply single-phase fault at FTTHOMP4 (652507) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the FTTHOMP4 (652507) to FTRANDL4 (652509) 230 kV line CKT 1. d. Trip the FTTHOMP4 (652507) to BIGBND14 (652540) 230 kV line CKT 1. **Trip generator BGBND12G (652542), BGBND34G (652543).**

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1003-SB	P4	**Stuck Breaker on FTTHOMP4 (652507) 230 kV bus.** a. Apply single-phase fault at FTTHOMP4 (652507) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the FTTHOMP4 (652507) to WESSINGTON 4 (652607) 230 kV line CKT 1. d. Trip the FTTHOMP4 (652507) to OAHE 4 (652519) 230 kV line CKT 2.
FLT1004-SB	P4	**Stuck Breaker on FTTHOMP4 (652507) 230 kV bus.** a. Apply single-phase fault at FTTHOMP4 (652507) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the FTTHOMP4 (652507) to LETCHER4 (652606) 230 kV line CKT 1. d. Trip the FTTHOMP4 (652507) to OAHE 4 (652519) 230 kV line CKT 3.
FLT1005-SB	P4	**Stuck Breaker on FTTHOMP4 (652507) 230 kV bus.** a. Apply single-phase fault at FTTHOMP4 (652507) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the FTTHOMP4 (652507) to G17-094-TAP (589324) 230 kV line CKT 2. d. Trip the FTTHOMP4 (652507) to OAHE 4 (652519) 230 kV line CKT 4.
FLT1006-SB	P4	**Stuck Breaker on FTTHOMP4 (652507) 230 kV bus.** a. Apply single-phase fault at FTTHOMP4 (652507) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the FTTHOMP4 (652507) to LAKPLAT-ER4 (655475) 230 kV line CKT 1. d. Trip the FTTHOMP4 (652507) to BIGBND24 (652541) 230 kV line CKT 2. **Trip generator BGBND56G (652544), BGBND78G (652545).**
FLT1007-SB	P4	**Stuck Breaker on HURON 4 (652514) 230 kV bus.** a. Apply single-phase fault at HURON 4 (652514) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the HURON 4 (652514) to WATERTN4 (652530) 230 kV line CKT 2. d. Trip the HURON (652514) to G17-094-TAP (589324) 230 kV line CKT 1.
FLT1008-SB	P4	**Stuck Breaker on HURON 4 (652514) 230 kV bus.** a. Apply single-phase fault at HURON 4 (652514) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the HURON 4 (652514) to CARPENTER 4 (652614) 230 kV line CKT 1. d. Trip the HURON (652514) to G17-094-TAP (589324) 230 kV line CKT 2.

6.3 Results

Table 6-2 shows the results of the fault events simulated for each of the modified cases. The associated stability plots are provided in Appendix D.

Table 6-2: GEN-2017-094 Dynamic Stability Results

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT01-3PH	Pass	Pass	Stable**	Pass	Pass	Stable
FLT02-3PH	Pass	Pass	Stable**	Pass	Pass	Stable**
FLT05-3PH	Pass	Pass	Stable**	Pass	Pass	Stable**
FLT06-3PH	Pass	Pass	Stable**	Pass	Pass	Stable**
FLT07-3PH	Pass	Pass	Stable**	Pass	Pass	Stable**
FLT08-3PH	Pass	Pass	Stable**	Pass	Pass	Stable**
FLT11-3PH	Pass	Pass	Stable**	Pass	Pass	Stable**
FLT28-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT42-3PH	Pass	Pass	Stable**	Pass	Pass	Stable**
FLT59-3PH	Pass	Pass	Stable**	Pass	Pass	Stable
FLT64-3PH	Pass	Pass	Stable**	Pass	Pass	Stable
FLT83-3PH	Pass	Pass	Stable**	Pass	Pass	Stable

Table 6-2 continued

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT94-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT95-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT96-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT103-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT104-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT105-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT130-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT205-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT206-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT207-3PH	Pass	Pass	Stable**	Pass	Pass	Stable
FLT214-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT216-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable**	Pass	Pass	Stable**
FLT9002-3PH	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Fail*	Fail*	Stable*	Fail*	Fail*	Stable*
FLT9017-3PH	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9029-3PH	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9030-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9031-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT103-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9029-PO1	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9030-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT104-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO2	Pass	Pass	Stable**	Pass	Pass	Stable**
FLT05-PO2	Pass	Pass	Stable**	Pass	Pass	Stable**
FLT06-PO2	Pass	Pass	Stable**	Pass	Pass	Stable**
FLT07-PO2	Pass	Pass	Stable**	Pass	Pass	Stable**
FLT08-PO2	Pass	Pass	Stable**	Pass	Pass	Stable**
FLT11-PO2	Pass	Pass	Stable**	Pass	Pass	Stable**
FLT42-PO2	Pass	Pass	Stable**	Pass	Pass	Stable**
FLT207-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO2	Pass	Pass	Stable**	Pass	Pass	Stable**
FLT9002-PO2	Pass	Pass	Stable**	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable**	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable**	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable**	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable**	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable**	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable**	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable

***FLT9016-3PH caused voltage violations in both the pre and post modification models**
****Oscillation found in both the pre and post modification models**

The results of the stability analysis showed that FLT9016-3PH, the loss of Chappelle to GEN-2017-114 Tap 345 kV line, caused a low voltage violation and localized voltage collapse at GEN-2017-114. This was observed in the DISIS-2017-002 case without and with the GEN-2017-094 modification as shown in Figure 6-1 and Figure 6-2 respectively. Therefore, the oscillations are not attributed to the GEN-2017-094 modification request. Note that at the time of this Study, the GEN-2017-114 interconnection request was already withdrawn from the SPP Active Queue and as such this issue is no longer relevant.

Figure 6-1: FLT9016-3PH GEN-2017-114 Voltage Issues (25SP DISIS Case)

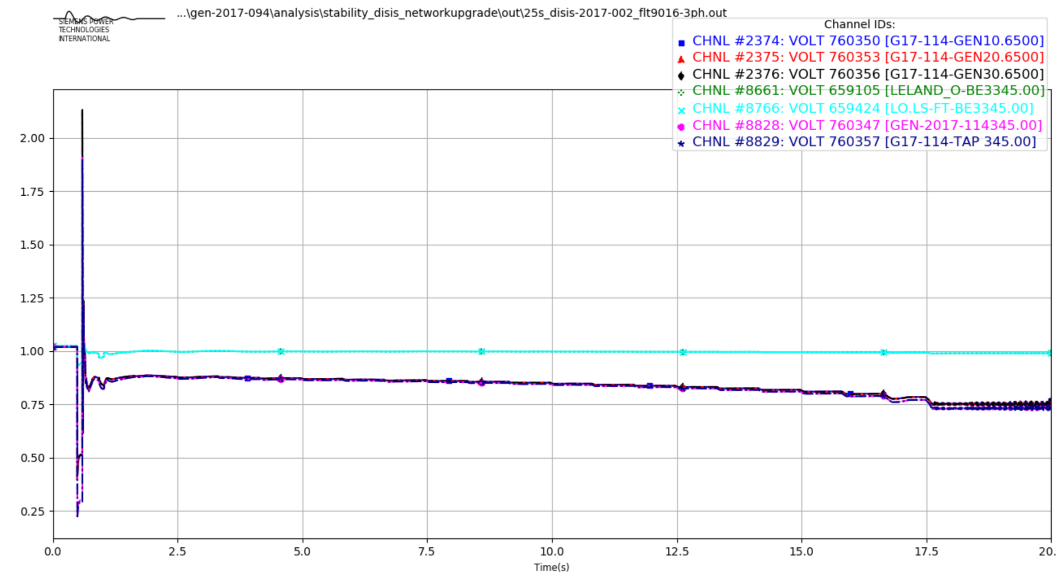
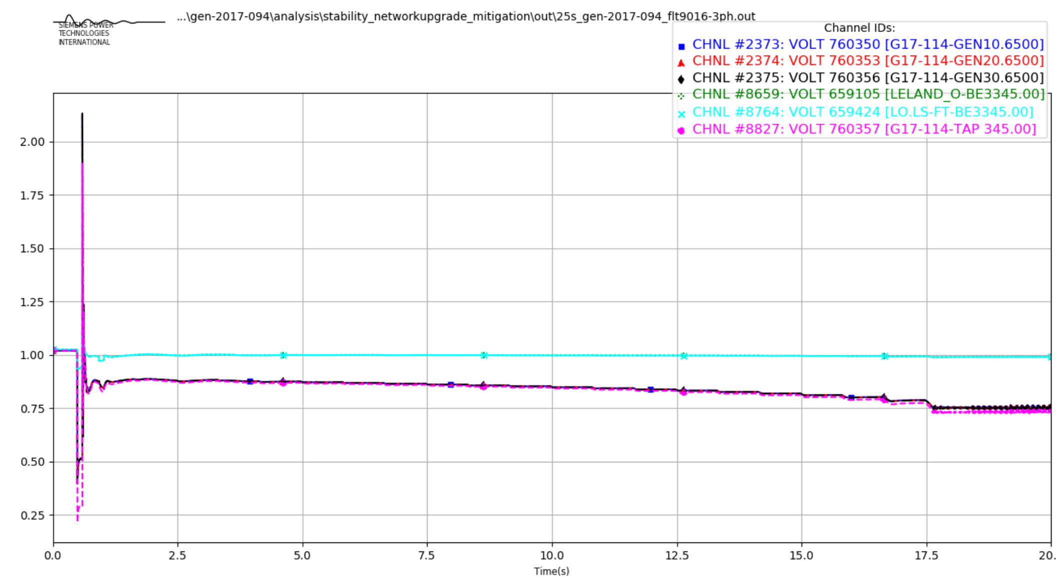


Figure 6-2: FLT9016-3PH GEN-2017-114 Voltage Issues (25SP Modification Case)



In addition, oscillations were observed for several generation units including CENTER2G (657748), COYOTE1G (661015), and HESKET3G (661102) under multiple contingencies. This was observed in both DISIS-2017-002 case without modification and with modification case. For example, this issue was observed for fault FLT02-3PH in the DISIS-2017-002 case without the GEN-2017-094 modification as shown in Figure 6-3 below and with the GEN-2017-094 modification as shown in Figure 6-4. Therefore, this issue was not attributed to the GEN-2017-094 modification request.

Figure 6-3: FLT02-3PH Oscillations (25SP DISIS Case)

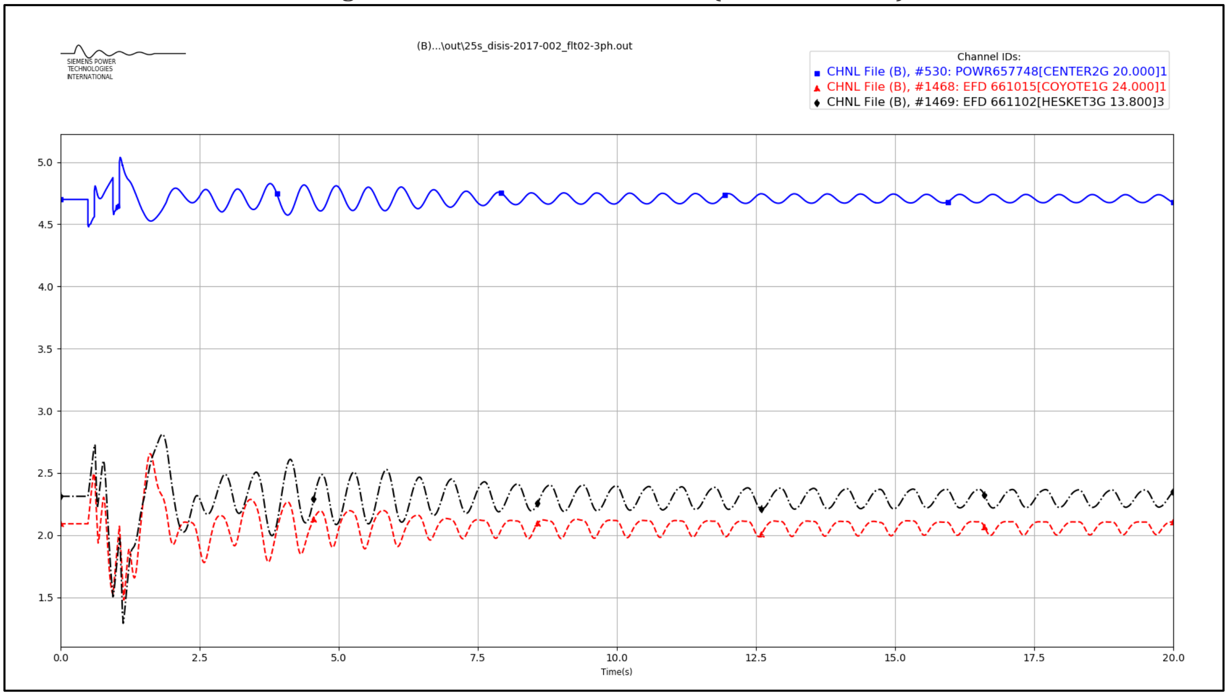
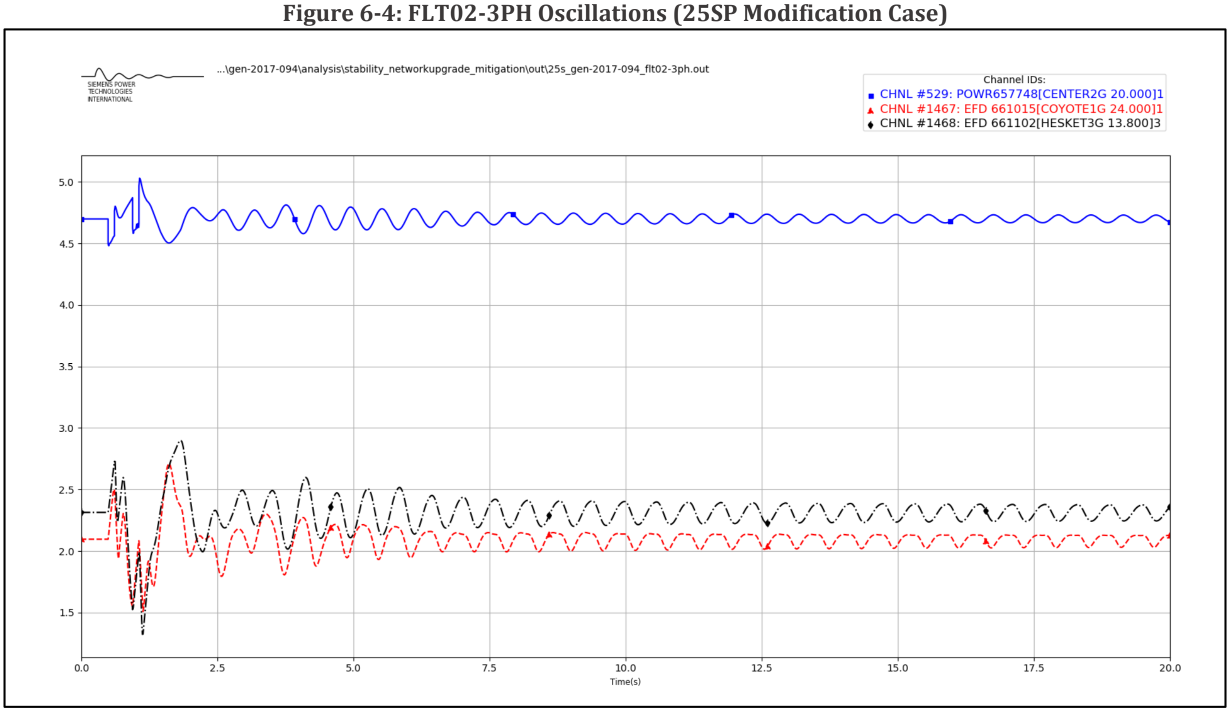


Figure 6-4: FLT02-3PH Oscillations (25SP Modification Case)



There were no damping or voltage recovery violations attributed to the GEN-2017-094 modification request observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

7.0 Modified Capacity Exceeds GIA Capacity

Under FERC Order 845, Interconnection Customers are allowed to request Interconnection Service that is lower than the full generating capacity of their planned generating facilities. The Interconnection Customers must install acceptable control and protection devices that prevent the injection above their requested Interconnection Service amount measured at the POI.

As such, Interconnection Customers are allowed to increase the generating capacity of a generating facility without increasing its Interconnection Service amount stated in its GIA. This is allowable as long as they install the proper control and protection devices, and the requested modification is not determined to be a Material Modification.

7.1 Results

The modified generating capacity of GEN-2017-094 (200.22 MW) exceeds the GIA Interconnection Service amount, 200 MW, as listed in Appendix A of the GIA.

The customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

8.0 Material Modification Determination

In accordance with Attachment V of SPP's Open Access Transmission Tariff, for modifications other than those specifically permitted by Attachment V, SPP shall evaluate the proposed modifications prior to making them and inform the Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Material Modification shall mean (1) modification to an Interconnection Request in the queue that has a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date; or (2) planned modification to an Existing Generating Facility that is undergoing evaluation for a Generating Facility Modification or Generating Facility Replacement, and has a material adverse impact on the Transmission System with respect to: i) steady-state thermal or voltage limits, ii) dynamic system stability and response, or iii) short-circuit capability limit; compared to the impacts of the Existing Generating Facility prior to the modification or replacement.

8.1 Results

SPP determined the requested modification is not a Material Modification based on the results of this Modification Request Impact Study performed by Aneden. Aneden evaluated the impact of the requested modification on the prior study results. Aneden determined that the requested modification did not negatively impact the prior study dynamic stability and short circuit results, and the modifications to the project were not significant enough to change the previously studied power flow conclusions.

This determination implies that any network upgrades already required by GEN-2017-094 would not be negatively impacted and that no new upgrades are required due to the requested modification, thus not resulting in a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.

9.0 Conclusions

The Interconnection Customer for GEN-2017-094 requested a Modification Request Impact Study to assess the impact of the turbine and facility change to 71 x GE 2.82 MW for a total capacity of 200.22 MW. This generating capacity for GEN-2017-094 (200.22 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 200 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

In addition, the modification request included changes to the collection system, generator step-up transformers, and main substation transformers.

SPP determined that power flow should not be performed based on the POI MW injection decrease of 1.11% compared to the DISIS-2017-002 power flow models (GEN-2017-094 dispatched to 100%). However, SPP determined that while the modification used the same turbine manufacturer, GE, the change in stability model from GEWTGCU1 and REGCA1 to GEWTG0705 required short circuit and dynamic stability analyses.

All analyses were performed using the PTI PSS/E version 34 software and the results are summarized below.

The results of the charging current compensation analysis using the 2025 Summer Peak and 2025 Winter Peak models showed that the GEN-2017-094 project needed a 11.4 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 9.3 MVAr found in the DISIS-2017-001 study[6]. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The short circuit analysis was performed using the 25SP model. The results from the short circuit analysis with the updated topology showed that the maximum GEN-2017-094 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2017-094 POI was no greater than 1.17 kA. All three-phase fault current levels within 5 buses of the POI with the GEN-2017-094 generator online were below 38 kA.

The dynamic stability analysis was performed using PTI PSS/E version 34.8 software for the two modified study models: 2025 Summer Peak and 2025 Winter Peak. 79 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

The results of the dynamic stability analysis showed that there were stability issues associated with GEN-2017-114, an interconnection request withdrawn from the SPP Active Queue. As such that issue is no longer relevant. In addition, oscillations were observed for several generation units including CENTER2G (657748), COYOTE1G (661015), and HESKET3G (661102) under multiple contingencies

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in the DISIS-2017-002 case and the case with the GEN-2017-094 modification. These issues were not attributed to the GEN-2017-094 modification request.

There were no damping or voltage recovery violations attributed to the GEN-2017-094 modification request observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

The requested modification has been determined by SPP to not be a Material Modification. The requested modification does not have a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date. As the requested modification places the generating capacity of the Interconnection Request at a higher amount than its Interconnection Service, the customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

In accordance with FERC Order No. 827, the generating facility will be required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation.

It is likely that the customer may be required to reduce its generation output to 0 MW in real-time, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of transmission service or delivery rights. If the customer wishes to obtain deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool’s OASIS by the customer.

ANEDEN
CONSULTING

Appendices

GEN-2017-094
Modification Request Impact Study

Date of Submittal

January 6, 2023

anedenconsulting.com

Appendix A

GEN-2017-094 Generator Dynamic Model

```
// *************** GEN-2017-094 100% **************
//
// POI tap on Fort Thompson-Huron 230 kV
//
// GE 2.82 MW * 71 = 200.22 MW
//
// Pmax=200.22 MW | Pgen=200.22 MW
//
// 0.87 PF Range

589323   'USRMDL'   1   'GEWTG0705'   1   1   30   64   11   29
    589323   1
      0   0   0   0   0   0   0   0   0   0   0   0   0   0
0   0   0   0   0   0   0
      0   0   0   0   0   0   0
      1.000   1.000   60.000   0.050   0.000   0.000
     -1.500   1.500   18.750   185.000   0.900   1.100
      0.250   1.330   0.700   20.000   3.000   0.020
      0.000   0.500   0.750   0.900   1.000   0.000
      0.000   0.750   1.230   1.230   100.000   0.100
      0.050   0.100   2.000   0.050   1.000   1.230
     -1.000   5.000   9999.000   -1.000   5.000   9999.000
     -1.000   5.000   9999.000   -1.000   5.000   9999.000
     -1.000   5.000   9999.000   -1.000   5.000   9999.000
     -1.000   5.000   9999.000   40.000   70.000   9999.000
     40.000   70.000   9999.000   9999.000/

589323   'USRMDL'   1   'GEWTE0705'   4   0   11   73   16   293
     589320   0   1   0   0   3   2   1   0
      1   0
      0.370   1.100   0.900   1.110   1.700   10.000
      0.200   66.000   1.200   0.000   1.300   1.000
      0.100   0.015   0.050   0.015   0.050   0.200
      0.020   0.015   0.150   5.000   0.020   0.400
      0.220   0.220   1.000   0.007   0.050   0.000
      0.000   0.030   0.500   0.000   -0.100   0.100
     -1.000   1.000   2.000   0.150   0.000   0.150
      0.142   -0.142   0.329   -0.329   0.329   -0.329
      0.010   0.450   1.100   1.100   0.600   0.600
     -1.000   -1.000   -0.600   -0.600   -0.600   -0.600
     -1.300   -1.300   0.000   0.500   0.900   1.100
      1.200   1.300   1.100   0.900   0.000   0.000
      0.020/

589323   'USRMDL'   1   'GEWTA0705'   5   0   7   84   21   67
      0   0   1   1   0   0   0
```

```
          2.820     71.000      1.064      6.027      1.500     125.66
          1.200      2.000      5.000      2.500    999.000   -999.000
          1.000      6.000      0.000     -0.500    960.000   1060.000
          0.000    700.000     10.000      0.248     -0.248     20.000
         20.000    -0.0050     0.0050      0.000      1.500      0.050
         -0.003    100.000    100.000     0.0690      0.150      0.800
          1.000      1.100      0.600      1.000      1.000      1.020
          0.500     60.036     63.036     65.000     65.000      0.000
        100.000    100.000    100.000     59.964     59.964     55.000
         55.000      0.000      0.000      0.000      0.000      0.050
          1.000      5.000      0.320      0.040      0.050      0.089
         -0.089      0.800      1.000      0.040      0.010      0.020
        999.000   -999.000      0.000      0.020    0.00167   -0.00167
         10.000    127.000      0.050      3.000      0.050      3.000/

58932301  'VTGTPAT'
       589323 589323  '1 '
     0.40000       5.0000      1.00000      0.80000E-01/
58932302  'VTGTPAT'
       589323 589323  '1 '
     0.60000       5.0000      1.70000      0.80000E-01/
58932303  'VTGTPAT'
       589323 589323  '1 '
     0.70000       5.0000      2.50000      0.80000E-01/
58932304  'VTGTPAT'
       589323 589323  '1 '
     0.75000       5.0000      3.00000      0.80000E-01/
58932305  'VTGTPAT'
       589323 589323  '1 '
     0.85000       5.0000      10.0000      0.80000E-01/
58932306  'VTGTPAT'
       589323 589323  '1 '
     0.90000       5.0000      600.00      0.80000E-01/
58932307  'VTGTPAT'
       589323 589323  '1 '
     0.00000       1.120      300.00      0.80000E-01/
58932308  'VTGTPAT'
       589323 589323  '1 '
     0.00000       1.150      30.000      0.80000E-01/
58932309  'VTGTPAT'
       589323 589323  '1 '
     0.00000       1.200      2.0000      0.80000E-01/
58932310  'VTGTPAT'
       589323 589323  '1 '
     0.00000       1.2500      0.5000      0.80000E-01/
58932311  'VTGTPAT'
```

```
          589323 589323  '1 '
        0.00000       1.3800      0.300       0.80000E-01/
58932312  'VTGTPAT'
          589323 589323  '1 '
        0.00000       1.5000      0.0300      0.80000E-01/
58932313  'VTGTPAT'
          589323 589323  '1 '
        0.00000       1.6000      0.0100      0.80000E-01/

58932321 'FRQTPAT'  589323 589323 '1'   55.0 65.0  0.10   0.08 /
58932322 'FRQTPAT'  589323 589323 '1'   57.0 63.0  60.0   0.08 /
```

Appendix B

Short Circuit Results

Table B-1: 25SP Short Circuit Results

BUS NUMBER	BUS NAME	Voltage (kV)	AREA	ZONE	3 Phase Fault Current (kA)		Difference (ON - OFF)		Distance from GEN POI Bus	Greater Than 40 kA
					GenON	GenOFF	Change	%	589324	
589324	G17-094-TAP	230	652	1604	11.348	10.181	1.167	11.46%	0	FALSE
589320	GEN-2017-094	230	652	1604	8.578	N/A	N/A	N/A	1	FALSE
652507	FTTHOMP4	230	652	1604	19.881	19.380	0.501	2.59%	1	FALSE
652514	HURON 4	230	652	1604	11.277	10.685	0.592	5.54%	1	FALSE
587764	G16-094-TAP	230	652	1604	8.982	8.903	0.079	0.89%	2	FALSE
652276	FTTHOMP8	69	652	1604	4.392	4.387	0.005	0.11%	2	FALSE
652506	FTTHOMP3	345	652	1604	9.185	9.082	0.103	1.13%	2	FALSE
652509	FTRANDL4	230	652	1604	10.614	10.590	0.024	0.23%	2	FALSE
652515	HURON 7	115	652	1604	15.049	14.668	0.381	2.60%	2	FALSE
652519	OAHE 4	230	652	1604	12.990	12.898	0.092	0.71%	2	FALSE
652530	WATERTN4	230	652	1604	14.492	14.399	0.093	0.65%	2	FALSE
652540	BIGBND14	230	652	1604	11.853	11.696	0.157	1.34%	2	FALSE
652541	BIGBND24	230	652	1604	11.772	11.617	0.155	1.33%	2	FALSE
652606	LETCHER4	230	652	1604	4.689	4.677	0.012	0.26%	2	FALSE
652607	WESSINGTON 4	230	652	1604	5.618	5.594	0.024	0.43%	2	FALSE
652614	CARPENTER 4	230	652	1604	6.949	6.787	0.162	2.39%	2	FALSE
655475	LAKPLAT-ER4	230	652	1632	5.546	5.526	0.020	0.36%	2	FALSE
659205	BROADLND-BE4	230	652	1628	10.183	9.715	0.468	4.82%	2	FALSE
587760	GEN-2016-094	230	652	1604	8.827	8.751	0.076	0.87%	3	FALSE
640540	MEADOWGROVE4	230	640	686	5.487	5.486	0.001	0.02%	3	FALSE
652284	HURON 8	69	652	1604	3.636	3.621	0.015	0.41%	3	FALSE
652510	FTRANDL7	115	652	1604	12.249	12.235	0.014	0.11%	3	FALSE
652520	OAHE 7	115	652	1603	10.715	10.692	0.023	0.22%	3	FALSE
652523	SIOUXFL4	230	652	1604	13.060	13.045	0.015	0.11%	3	FALSE
652526	UTICAJC4	230	652	1604	8.185	8.180	0.005	0.06%	3	FALSE
652528	WOONSKT7	115	652	1604	5.197	5.175	0.022	0.43%	3	FALSE
652529	WATERTN3	345	652	1604	10.313	10.280	0.033	0.32%	3	FALSE
652531	WATERTN7	115	652	1604	13.486	13.458	0.028	0.21%	3	FALSE
652565	SIOUXCY4	230	652	1601	19.185	19.179	0.006	0.03%	3	FALSE
652582	APPLEDORN 4	230	652	1604	7.079	7.073	0.006	0.08%	3	FALSE
652609	LETCHER7	115	652	1604	5.953	5.942	0.011	0.19%	3	FALSE
652630	WATERTNCAP 4	230	652	1604	14.319	14.228	0.091	0.64%	3	FALSE
652806	FTTHOM1-LNX3	345	652	1604	9.120	9.019	0.101	1.12%	3	FALSE
652807	FTTHOM2-LNX3	345	652	1604	9.185	9.082	0.103	1.13%	3	FALSE
655153	MOS-AMES-ER8	69	652	1632	4.332	4.328	0.004	0.09%	3	FALSE
655465	BLAIR-ER4	230	652	1632	9.839	9.825	0.014	0.14%	3	FALSE
655476	LAKPLAT-ER8	69	652	1632	3.997	3.993	0.004	0.10%	3	FALSE
655481	REDFELD-ER7	115	652	1632	4.084	4.071	0.013	0.32%	3	FALSE
655487	SULLYBT-ER4	230	652	1632	6.053	6.036	0.017	0.28%	3	FALSE
655499	CARPENTR-ER8	69	652	1632	3.164	3.153	0.011	0.35%	3	FALSE
659120	BROADLND-BE3	345	652	1628	4.625	4.508	0.117	2.60%	3	FALSE
659122	STORLA__-BE4	230	652	1628	5.315	5.295	0.020	0.38%	3	FALSE
659188	PHILIP_T-BE4	230	652	1628	5.337	5.332	0.005	0.09%	3	FALSE
659295	SD.PW1__-BE4	230	652	1628	4.366	4.352	0.014	0.32%	3	FALSE
660003	HURON WPARK7	115	652	1634	9.508	9.378	0.130	1.39%	3	FALSE
660009	HURON BTAP 7	115	652	1634	14.603	14.247	0.356	2.50%	3	FALSE
588590	GEN-2017-014	230	652	1603	5.337	5.332	0.005	0.09%	4	FALSE
602004	SPLT RK4	230	600	606	12.637	12.623	0.014	0.11%	4	FALSE
620314	BIGSTON4	230	620	658	16.463	16.456	0.007	0.04%	4	FALSE
640133	COLMBUS4	230	640	686	11.318	11.317	0.001	0.01%	4	FALSE
640349	SPENCER7	115	640	686	4.506	4.505	0.001	0.02%	4	FALSE
640386	TWIN CH4	230	640	686	7.905	7.905	0.000	0.00%	4	FALSE
648506	PR BRZ 4	230	645	691	4.111	4.111	0.000	0.00%	4	FALSE
652242	WATERT18	69	652	1604	3.922	3.920	0.002	0.05%	4	FALSE
652398	VFODNES4	230	652	1604	6.854	6.850	0.004	0.06%	4	FALSE
652475	BONESTL7	115	652	1603	3.466	3.465	0.001	0.03%	4	FALSE
652476	EAGLEBT7	115	652	1603	1.935	1.935	0.000	0.00%	4	FALSE
652484	NUNDRWD4	230	652	1603	3.966	3.965	0.001	0.03%	4	FALSE
652501	ARMOUR 7	115	652	1604	4.138	4.135	0.003	0.07%	4	FALSE
652504	BROOKNG7	115	652	1604	7.195	7.192	0.003	0.04%	4	FALSE
652513	HANLON 4	230	652	1604	5.495	5.488	0.007	0.13%	4	FALSE
652522	SUMMIT-7	115	652	1604	4.723	4.721	0.002	0.04%	4	FALSE
652524	SIOUXFL7	115	652	1604	25.941	25.923	0.018	0.07%	4	FALSE
652550	GRANITF4	230	652	1604	13.059	13.050	0.009	0.07%	4	FALSE
652552	SIOUXCY2	230	652	1601	19.185	19.179	0.006	0.03%	4	FALSE
652566	SIOUXCY5	161	652	1601	20.200	20.197	0.003	0.01%	4	FALSE
652567	DENISON4	230	652	1601	4.874	4.873	0.001	0.02%	4	FALSE
652568	GROTONSOUTH7	115	652	1604	17.149	17.131	0.018	0.11%	4	FALSE
652600	ASH TAP	115	652	1603	8.170	8.157	0.013	0.16%	4	FALSE
652604	APPLEDORN 8	69	652	1604	2.482	2.481	0.001	0.04%	4	FALSE

Table B-1 Continued

BUS NUMBER	BUS NAME	Voltage (kV)	AREA	ZONE	3 Phase Fault Current (kA)		Difference (ON - OFF)		Distance from GEN POI Bus	Greater Than 40 kA
					GenON	GenOFF	Change	%	589324	
652626	UTICAJC7	115	652	1604	8.668	8.665	0.003	0.03%	4	FALSE
652829	WATERTN-LNX3	345	652	1604	10.305	10.272	0.033	0.32%	4	FALSE
652833	GRPRAR2-LNX3	345	652	1604	6.614	6.606	0.008	0.12%	4	FALSE
654457	PRVLNG16	230	652	1604	8.135	8.130	0.005	0.06%	4	FALSE
655063	SW-HURN1-ER8	69	652	1632	3.583	3.569	0.014	0.39%	4	FALSE
655066	SW-HURN2-ER8	69	652	1632	3.620	3.606	0.014	0.39%	4	FALSE
655067	SW-HURN3-ER8	69	652	1632	3.624	3.610	0.014	0.39%	4	FALSE
655073	MOS-CRPN-ER8	69	652	1632	2.425	2.418	0.007	0.29%	4	FALSE
655158	MOS-HYDE-ER8	69	652	1632	3.440	3.438	0.002	0.06%	4	FALSE
655250	CHMBRLAN-ER8	69	652	1632	1.576	1.576	0.000	0.00%	4	FALSE
655328	BIGBEND-ER8	69	652	1632	3.214	3.212	0.002	0.06%	4	FALSE
655352	AMES-ER8	69	652	1632	1.334	1.334	0.000	0.00%	4	FALSE
655355	WOONSKT-ER8	69	652	1632	3.543	3.536	0.007	0.20%	4	FALSE
655385	MOS-LKPL-ER8	69	652	1632	3.982	3.979	0.003	0.08%	4	FALSE
655412	CRPNTR-ER8	69	652	1632	2.806	2.797	0.009	0.32%	4	FALSE
655417	ROSWELL-ER7	115	652	1632	2.584	2.582	0.002	0.08%	4	FALSE
655462	ARLNGTN-ER7	115	652	1632	4.336	4.333	0.003	0.07%	4	FALSE
655466	BLAIR-ER8	69	652	1632	2.526	2.525	0.001	0.04%	4	FALSE
655482	REDFELD-ER8	69	652	1632	2.791	2.788	0.003	0.11%	4	FALSE
655484	RASMUSN-ER4	230	652	1632	6.612	6.610	0.002	0.03%	4	FALSE
655488	SULLYBT-ER8	69	652	1632	2.345	2.344	0.001	0.04%	4	FALSE
655490	WHTSWAN-ER7	115	652	1632	11.947	11.934	0.013	0.11%	4	FALSE
655510	SB.LS-WK-ER4	230	652	1632	6.053	6.036	0.017	0.28%	4	FALSE
658089	WTR15AV7	115	652	1624	11.567	11.546	0.021	0.18%	4	FALSE
658094	WTRPELI7	115	652	1624	9.234	9.221	0.013	0.14%	4	FALSE
658174	IRVSIMM7	115	652	1624	7.731	7.719	0.012	0.16%	4	FALSE
659123	STORLA__-BE7	115	652	1628	6.463	6.441	0.022	0.34%	4	FALSE
659130	CHAPELLE-BE3	345	652	1628	6.619	6.579	0.040	0.61%	4	FALSE
659165	G09_001IST	345	652	659	6.512	6.503	0.009	0.14%	4	FALSE
659192	PHILIP__-BE4	230	652	1628	4.031	4.028	0.003	0.07%	4	FALSE
659311	PAHOJA__-BE4	230	652	1628	7.266	7.262	0.004	0.06%	4	FALSE
659421	BD.LS-AV-BE3	345	652	1628	4.625	4.508	0.117	2.60%	4	FALSE
660004	MITCHELL 7	115	652	1634	5.690	5.680	0.010	0.18%	4	FALSE
660008	MITCHELL NW7	115	652	1634	5.312	5.302	0.010	0.19%	4	FALSE
660012	HURON WPARK8	69	652	1634	6.693	6.666	0.027	0.41%	4	FALSE
660040	DAKOTACCESS7	115	652	1634	4.436	4.416	0.020	0.45%	4	FALSE
762237	G17-175TAP	230	526	1	6.739	6.735	0.004	0.06%	4	FALSE
602008	MINVALT4	230	600	606	12.897	12.889	0.008	0.06%	5	FALSE
602009	MNVLTAP4	230	600	606	12.857	12.849	0.008	0.06%	5	FALSE
603009	GRANT 7	115	600	606	3.930	3.929	0.001	0.03%	5	FALSE
603012	LAWRENC7	115	600	606	29.230	29.210	0.020	0.07%	5	FALSE
603016	SPLT RK7	115	600	606	36.950	36.923	0.027	0.07%	5	FALSE
619975	GRE-WILLMAR4	230	615	643	5.322	5.321	0.001	0.02%	5	FALSE
620214	BIGSTON7	115	620	658	17.688	17.683	0.005	0.03%	5	FALSE
620322	BSSOUTH4	230	620	658	16.432	16.425	0.007	0.04%	5	FALSE
620325	BROWNSV4	230	620	658	5.934	5.933	0.001	0.02%	5	FALSE
635223	PLYMOTH5	161	635	679	19.767	19.764	0.003	0.02%	5	FALSE
640126	E.COL. 4	230	640	686	9.932	9.931	0.001	0.01%	5	FALSE
640131	COLMB.W4	230	640	686	9.709	9.708	0.001	0.01%	5	FALSE
640134	KELLY 7	115	640	686	17.514	17.513	0.001	0.01%	5	FALSE
640305	ONEILL 7	115	640	686	3.841	3.840	0.001	0.03%	5	FALSE
640343	SHELCRK4	230	640	686	10.628	10.627	0.001	0.01%	5	FALSE
640387	TWIN CH7	115	640	686	10.125	10.124	0.001	0.01%	5	FALSE
640404	WAYSIDE4	230	652	686	2.766	2.765	0.001	0.04%	5	FALSE
640560	WAKEFIELD 4	230	640	686	6.101	6.100	0.001	0.02%	5	FALSE
652209	SUMMIT-8	69	652	1604	2.693	2.693	0.000	0.00%	5	FALSE
652225	BROOKNG8	69	652	1604	2.910	2.910	0.000	0.00%	5	FALSE
652235	SIOUXFL8	69	652	1604	3.879	3.878	0.001	0.03%	5	FALSE
652243	FAITH 7	115	652	1603	2.452	2.451	0.001	0.04%	5	FALSE
652249	ARMOUR 8	69	652	1604	2.430	2.429	0.001	0.04%	5	FALSE
652259	EAGLEBE8	69	652	1603	1.620	1.619	0.001	0.06%	5	FALSE
652260	EAGLEBW8	69	652	1603	2.122	2.121	0.001	0.05%	5	FALSE
652455	ROBERTSCTY7	115	652	1604	3.126	3.126	0.000	0.00%	5	FALSE
652474	AURORA 7	115	652	1603	4.505	4.504	0.001	0.02%	5	FALSE
652478	GREGORY7	115	652	1603	2.124	2.124	0.000	0.00%	5	FALSE
652481	MIDLAND7	115	652	1603	3.375	3.373	0.002	0.06%	5	FALSE
652485	NUNDRWD7	115	652	1603	6.822	6.819	0.003	0.04%	5	FALSE
652487	PHILIP 7	115	652	1603	5.865	5.861	0.004	0.07%	5	FALSE
652489	PIERRE 7	115	652	1603	7.762	7.750	0.012	0.15%	5	FALSE
652502	BERSFRD7	115	652	1604	3.842	3.842	0.000	0.00%	5	FALSE
652505	FLANDRU7	115	652	1604	4.261	4.260	0.001	0.02%	5	FALSE

Table B-1 Continued

BUS NUMBER	BUS NAME	Voltage (kV)	AREA	ZONE	3 Phase Fault Current (kA)		Difference (ON - OFF)		Distance from GEN POI Bus	Greater Than 40 kA
					GenON	GenOFF	Change	%	589324	
652512	GROTON 7	115	652	1604	17.103	17.085	0.018	0.11%	5	FALSE
652518	MTVERN 7	115	652	1604	4.391	4.385	0.006	0.14%	5	FALSE
652525	TYNDALL7	115	652	1604	3.737	3.736	0.001	0.03%	5	FALSE
652532	GR PRAIRIE 3	345	652	1604	6.614	6.606	0.008	0.12%	5	FALSE
652537	WHITE 3	345	652	1604	18.407	18.386	0.021	0.11%	5	FALSE
652538	WHITE 7	115	652	1604	9.125	9.121	0.004	0.04%	5	FALSE
652551	GRANITF7	115	652	1604	17.827	17.820	0.007	0.04%	5	FALSE
652554	MORRIS 4	230	652	1605	4.565	4.565	0.000	0.00%	5	FALSE
652561	DENISON5	161	652	1601	5.944	5.943	0.001	0.02%	5	FALSE
652563	SPENCER5	161	652	1601	9.466	9.466	0.000	0.00%	5	FALSE
652564	SIOUXCY3	345	652	1601	14.606	14.603	0.003	0.02%	5	FALSE
652574	SIOUXCY8	69	652	1601	18.220	18.219	0.001	0.01%	5	FALSE
652583	DENISON8	69	652	1601	11.721	11.721	0.000	0.00%	5	FALSE
652884	NUNDRWD-LNX3	230	652	1603	3.959	3.958	0.001	0.03%	5	FALSE
654455	PRVLNG23	115	652	1604	6.755	6.753	0.002	0.03%	5	FALSE
655054	MOS-RDFL-ER8	69	652	1632	2.034	2.032	0.002	0.10%	5	FALSE
655055	SW-YALE-ER8	69	652	1632	1.171	1.170	0.001	0.09%	5	FALSE
655056	SW-WILLO-ER8	69	652	1632	1.551	1.548	0.003	0.19%	5	FALSE
655058	MOS-HRON-ER8	69	652	1632	2.620	2.612	0.008	0.31%	5	FALSE
655059	MOS-ASHT-ER8	69	652	1632	1.622	1.620	0.002	0.12%	5	FALSE
655064	SW-HURN4-ER8	69	652	1632	3.559	3.545	0.014	0.39%	5	FALSE
655072	SW-SANDC-ER8	69	652	1632	2.282	2.279	0.003	0.13%	5	FALSE
655079	MOS-KLKP-ER8	69	652	1632	0.767	0.767	0.000	0.00%	5	FALSE
655080	MOS-HLTP-ER8	69	652	1632	1.303	1.302	0.001	0.08%	5	FALSE
655108	MOS-RVLE-ER8	69	652	1632	3.885	3.883	0.002	0.05%	5	FALSE
655111	SW-SHERI-ER8	69	652	1632	3.276	3.275	0.001	0.03%	5	FALSE
655236	MORNINGS-ER8	69	652	1632	1.853	1.849	0.004	0.22%	5	FALSE
655238	FRANKFRT-ER8	69	652	1632	2.073	2.071	0.002	0.10%	5	FALSE
655294	MORITZ-ER8	69	652	1632	2.098	2.097	0.001	0.05%	5	FALSE
655329	GANNVALL-ER8	69	652	1632	0.862	0.861	0.001	0.12%	5	FALSE
655334	OKOBOJO-ER8	69	652	1632	2.335	2.334	0.001	0.04%	5	FALSE
655373	MOS-SLY2-ER8	69	652	1632	2.342	2.340	0.002	0.09%	5	FALSE
655377	SW1145-ER7	115	652	1632	24.670	24.653	0.017	0.07%	5	FALSE
655384	NWPS8645-ER8	69	652	1632	2.172	2.171	0.001	0.05%	5	FALSE
655386	MOS-RVR1-ER8	69	652	1632	2.078	2.077	0.001	0.05%	5	FALSE
655418	FREEMAN-ER7	115	652	1632	2.550	2.549	0.001	0.04%	5	FALSE
655419	SW561-ER7	115	652	1632	5.060	5.058	0.002	0.04%	5	FALSE
655457	BRISTOL-ER7	115	652	1632	4.600	4.598	0.002	0.04%	5	FALSE
655463	ARLNGTN-ER8	69	652	1632	2.627	2.626	0.001	0.04%	5	FALSE
655468	VFODNES-ER7	115	652	1632	4.918	4.917	0.001	0.02%	5	FALSE
655469	VFODNES-ER8	69	652	1632	4.177	4.176	0.001	0.02%	5	FALSE
655485	RASMUSN-ER8	69	652	1632	3.158	3.158	0.000	0.00%	5	FALSE
655493	HANLON-ER7	115	652	1632	3.823	3.821	0.002	0.05%	5	FALSE
655494	HANLON1-ER8	69	652	1632	5.113	5.110	0.003	0.06%	5	FALSE
655495	HANLON2-ER8	69	652	1632	5.113	5.110	0.003	0.06%	5	FALSE
655507	LKCOCHRN-ER8	69	652	1632	1.386	1.386	0.000	0.00%	5	FALSE
655765	WHITLOCK_-RM	230	652	1676	4.321	4.315	0.006	0.14%	5	FALSE
658088	WTREAST7	115	652	1624	10.448	10.432	0.016	0.15%	5	FALSE
658092	WTRWEST7	115	652	1624	9.145	9.132	0.013	0.14%	5	FALSE
658148	BMUOLD77	115	652	1624	6.040	6.038	0.002	0.03%	5	FALSE
658154	BMU34AT7	115	652	1624	5.303	5.301	0.002	0.04%	5	FALSE
658176	GARFLD 7	115	652	1624	6.764	6.755	0.009	0.13%	5	FALSE
659160	GROTON__-BE3	345	652	1628	6.602	6.594	0.008	0.12%	5	FALSE
659187	GROTON__-BE7	115	652	1628	17.133	17.115	0.018	0.11%	5	FALSE
659275	GROTON_G-BE7	115	652	1628	16.741	16.724	0.017	0.10%	5	FALSE
659310	ORDWAY__-BE7	115	652	1628	7.351	7.348	0.003	0.04%	5	FALSE
659376	DRYCREEK-BE4	230	652	1628	2.982	2.981	0.001	0.03%	5	FALSE
659420	AV.LS-BD-BE3	345	652	1628	18.538	18.522	0.016	0.09%	5	FALSE
659428	CC.LS-LO-BE3	345	652	1628	6.589	6.549	0.040	0.61%	5	FALSE
659433	TRIPLEH__UA3	345	652	1681	6.551	6.512	0.039	0.60%	5	FALSE
659472	CROCKER_-UA3	345	652	659	5.567	5.561	0.006	0.11%	5	FALSE
659716	MAPLETAP-LO7	115	652	1631	12.521	12.516	0.005	0.04%	5	FALSE
659735	CLEVELND-LO4	230	652	1631	4.849	4.848	0.001	0.02%	5	FALSE
659900	EAGLE___-NI4	230	652	1633	7.115	7.113	0.002	0.03%	5	FALSE
660002	REDFIELD 7	115	652	1634	3.982	3.970	0.012	0.30%	5	FALSE
660005	TRIPP JCT 7	115	652	1634	3.938	3.936	0.002	0.05%	5	FALSE
660007	MENNO JCT 7	115	652	1634	6.445	6.443	0.002	0.03%	5	FALSE
660026	NAPA JCT 7	115	652	1634	7.722	7.720	0.002	0.03%	5	FALSE
660309	HUR 9THST J	69	652	1634	5.742	5.724	0.018	0.31%	5	FALSE
660313	HUR 4TH ST	69	652	1634	4.988	4.972	0.016	0.32%	5	FALSE
660320	WOLSEY	69	652	1634	3.017	3.012	0.005	0.17%	5	FALSE
760515	GEN-2017-222	230	652	1	3.808	3.808	0.000	0.00%	5	FALSE
762238	GEN-2017-175	230	652	1	6.537	6.534	0.003	0.05%	5	FALSE

Appendix C

SPP Disturbance Performance Requirements

Southwest Power Pool Disturbance Performance Requirements

Revision 3.0

July 21, 2016

Southwest Power Pool

Revision History

Version Number	Author	Change Description	Comments
1.0 (1/13/2013)	Transient Stability Task Force	First draft	TWG approval of Rotor Angle Damping
1.1 (7/31/2013)	Transmission Working Group	Approval of entire document	Approval of both Rotor Angle Damping and Transient Voltage requirements and addressed items regarding SPPR figure.
2.0 (12/15/2015)	Transmission Working Group	Revision to Transient Voltage Requirements	Addition of 2.5 seconds delay of looking at voltage being above 0.7 p.u.
3.0 (7/21/2016)	Dynamic Load Task Force	Revision to Rotor Angle Damping Requirements	Edited verbiage to clarify rotor angle requirements.

Southwest Power Pool
Disturbance Performance Requirements

OVERVIEW

These Disturbance Performance Requirements ("Requirements") shall be applicable to the Bulk Electric System within the Southwest Power Pool Planning Area. Utilization of these Requirements applies to all registered entities within the Southwest Power Pool Planning Area. These Requirements shall not be applicable to facilities that are not part of Bulk Electric System. More stringent Requirements are at the sole discretion of each Transmission Planner.

Transient and dynamic stability assessments are generally performed to assure adequate avoidance of loss of generator synchronism and prevention of system voltage collapse within the first 20 seconds after a system disturbance. These Requirements provide a basis for evaluating the system response during the initial transient period following a disturbance on the Bulk Electric System by establishing minimum requirements for machine rotor angle damping and transient voltage recovery.

ROTOR ANGLE DAMPING REQUIREMENT

Machine Rotor Angles shall exhibit well damped angular oscillations following a disturbance on the Bulk Electric System for all NERC TPL-001-4 P1 through P7 events.

Machines with rotor angle deviations greater than or equal to 16 degrees (measured as absolute maximum peak to absolute minimum peak) shall be evaluated against SPPR1 or SPPR5 requirements below. Machines with rotor angle deviations less than 16 degrees which do not exhibit convergence shall be evaluated on an individual basis. Rotor angle deviations will be calculated relative to the system swing machine.

Well damped angular oscillations shall meet one of the following two requirements when calculated directly from the rotor angle:

1. Successive Positive Peak Ratio One (SPPR1) must be less than or equal to 0.95 where SPPR1 is calculated as follows:

$$\text{SPPR1} = \frac{\text{Peak Rotor Angle of } 2^{nd} \text{ Positive Peak minus Minimum Value}}{\text{Peak Rotor Angle of } 1^{st} \text{ Positive Peak minus Minimum Value}} \leq 0.95$$

   -or- Damping Factor % = (1 – SPPR1) x 100% $\geq$ 5%

   The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

   Damping Ratio $\geq$ 0.0081633

2. Successive Positive Peak Ratio Five (SPPR5) must be less than or equal to 0.774 where SPPR5 is calculated as follows:

$$\text{SPPR5} = \frac{\text{Peak Rotor Angle of } 6^{th} \text{ Positive Peak minus Minimum Value}}{\text{Peak Rotor Angle of } 1^{st} \text{ Positive Peak minus Minimum Value}} \leq 0.774$$

   -or- Damping Factor % = (1 – SPPR5) x 100% $\geq$ 22.6%

   The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

   Damping Ratio $\geq$ 0.0081633

Qualitatively, these Requirements are shown in Figure 1 & 2 below.

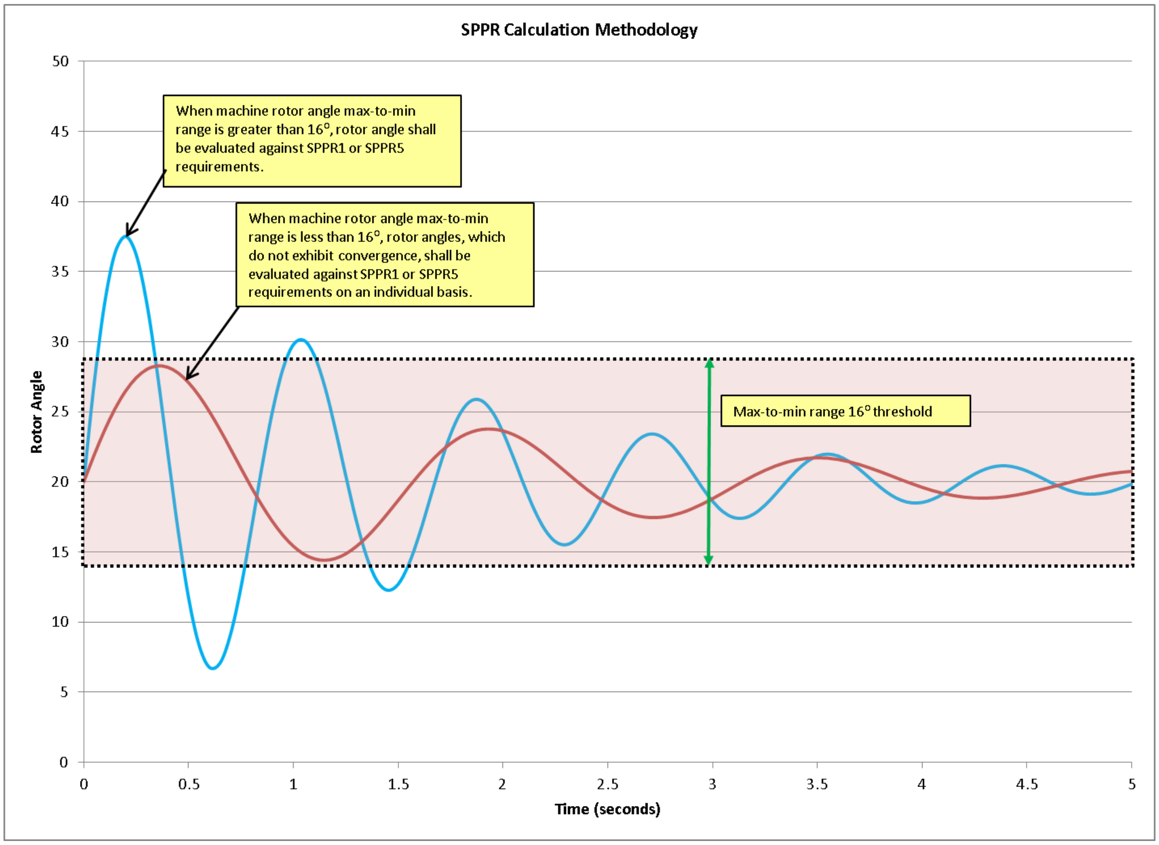

Figure 1. Applicability of 16 Degree Threshold

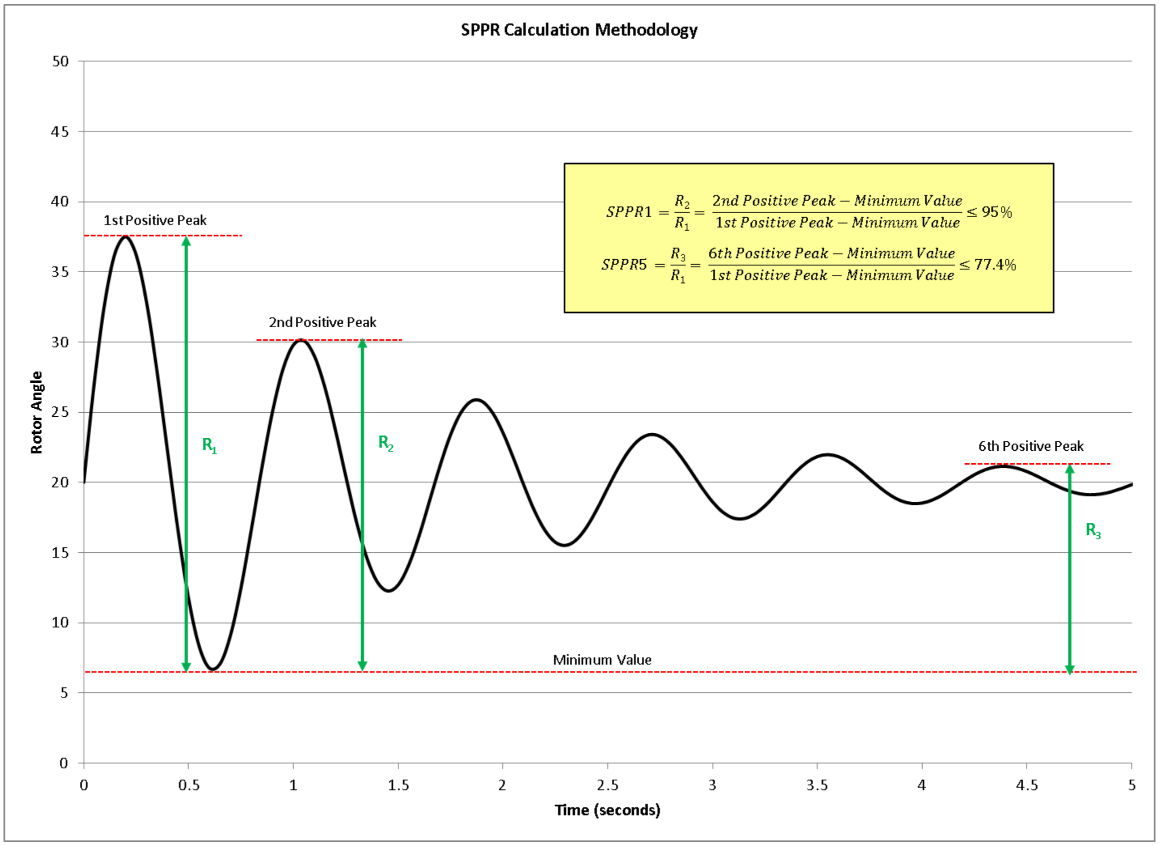

Figure 2. SPPR1 and SPPR5 Calculations

TRANSIENT VOLTAGE RECOVERY REQUIREMENT

Bus voltages on the Bulk Electric System shall recover above 0.70 per unit, 2.5 seconds after the fault is cleared. Bus voltages shall not swing above 1.20 per unit after the fault is cleared, unless affected transmission system elements are designed to handle the rise above 1.2 per unit.

Qualitatively, this Requirement is shown in Figure 3 below.

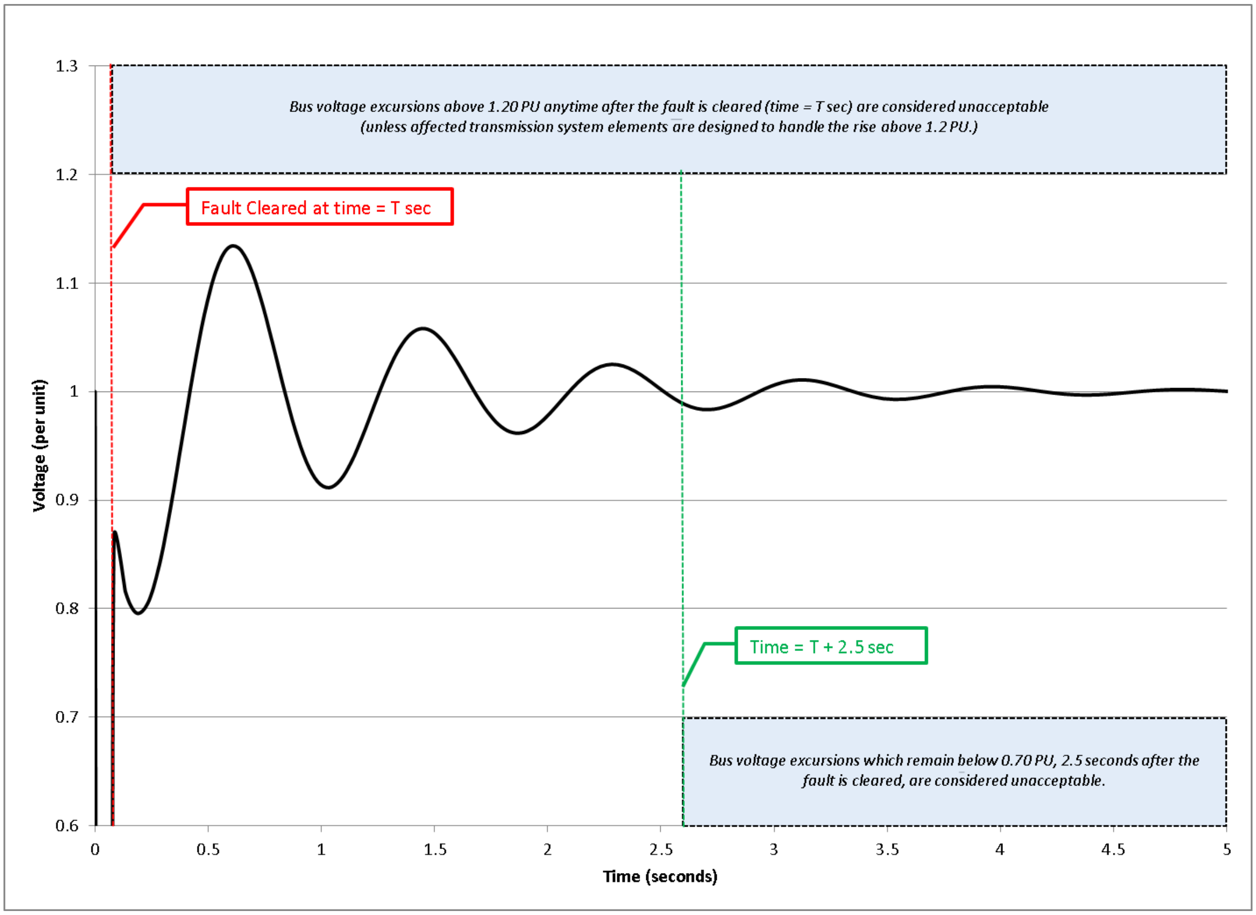

Figure 3. Transient Voltage Recovery Requirement

Appendix D

GEN-2017-094

Dynamic Stability Simulation Plots

2025 Winter Peak Plots

Including Prior Outage Plots

GEN-2017-094_25WP_Plots.pdf

2025 Summer Peak Plots

Including Prior Outage Plots

GEN-2017-094_25SP_Plots.pdf