Report on

GEN-2016-119 Modification Request Impact Study

Revision R1 January 19, 2023

Submitted to
Southwest Power Pool

anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
1/19/2023	Aneden Consulting	Initial Report Issued

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2016-119, an active Generation Interconnection Request (GIR) with a Point of Interconnection (POI) on the Spring Creek to Sooner 345 kV line.

The GEN-2016-119 project interconnects in the Oklahoma Gas & Electric (OKGE) control area with a capacity of 600 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2016-119 to change the turbine configuration to 176 x GE 3.43 MW for a total capacity of 603.68 MW. This generating capacity for GEN-2016-119 (603.68 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 600 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. The existing and modified configurations for GEN-2016-119 are shown in Table ES-2.

Table ES-1: GEN-2016-119 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2016-119	Tap on Spring Creek 345 kV (514881) to Sooner 345 kV (514803) (G16-119-TAP 587804)	300 x Vestas 2.0 MW	600

Table ES-2: GEN-2016-119 Modification Request

Facility	Existing Configuration		Modification Configuration			
Point of Interconnection	Spring Creek 345 kV (514881) to Sooner 345 kV (514803) (G16-119-TAP 587804)		Spring Creek 345 kV (514881) to Sooner 345 kV (514803) (G16-119-TAP 587804)			
Configuration/Capacity	300 x Vestas 2.0 MW = 600 MW		176 x GE 3.43 MW = 603.68 MW POI limited to 600 MW			
Generation Interconnection Line	G16-119-TAP to GEN-2016-119: Length = 18.7 miles R = 0.000500 pu X = 0.009040 pu B = 0.167440 pu Rating = 0 MVA	GEN-2016-119 to GEN2016-119B: Length = 5.3 miles R = 0.000520 pu X = 0.003370 pu B = 0.035690 pu Rating = 0 MVA	G16-119-TAP to GEN-2016-119: Length = 5.87 miles R = 0.000193 pu X = 0.002772 pu B = 0.052994 pu Rating [A/B] = 1395/1543 MVA		GEN-2016-119 to GEN2016-119B: Length = 10.53 miles R = 0.000452 pu X = 0.005047 pu B = 0.093546 pu Rating [A/B] = 1168/1288 MVA	
Main Substation Transformer[1]	X = 12.247%, R = 0.278%, Winding MVA = 216 MVA, Rating MVA = 360 MVA	X = 12.247%, R = 0.278%, Winding MVA = 216 MVA, Rating MVA = 360 MVA	X = 9.802%, R = 0.238%, Winding MVA = 113 MVA, Rating MVA = 189 MVA	X = 9.802%, R = 0.238%, Winding MVA = 113 MVA, Rating MVA = 189 MVA	X = 9.802%, R = 0.238%, Winding MVA = 113 MVA, Rating MVA = 189 MVA	X = 9.802%, R = 0.238%, Winding MVA = 113 MVA, Rating MVA = 189 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 141 X = 7.759%, R = 0.799%, Winding MVA = 296.1 MVA, Rating MVA = 296.1 MVA	Gen 2 Equivalent Qty: 159 X = 7.759%, R = 0.799%, Winding MVA = 333.9 MVA, Rating MVA = 333.9 MVA	Gen 1 Equivalent Qty: 45 X = 7.484%, R = 0.998%, Winding MVA = 171.495 MVA, Rating MVA[2] = 171.5 MVA	Gen 2 Equivalent Qty: 43 X = 7.484%, R = 0.998%, Winding MVA = 163.873 MVA, Rating MVA[2] = 163.9 MVA	Gen 3 Equivalent Qty: 45 X = 7.484%, R = 0.998%, Winding MVA = 171.495 MVA, Rating MVA[2] = 171.5 MVA	Gen 4 Equivalent Qty: 43 X = 7.484%, R = 0.998%, Winding MVA = 163.873 MVA, Rating MVA[2] = 163.9 MVA
Equivalent Collector Line[3]	R = 0.002300 pu X = 0.003700 pu B = 0.147880 pu	R = 0.003200 pu X = 0.005100 pu B = 0.219790 pu	R = 0.010863 pu X = 0.012468 pu B = 0.085781 pu	R = 0.009558 pu X = 0.009343 pu B = 0.074332 pu	R = 0.010967 pu X = 0.014691 pu B = 0.087661 pu	R = 0.007141 pu X = 0.007362 pu B = 0.051911 pu
Generator Dynamic Model[4] & Power Factor	141 x Vestas 2.0 MW (VC200453400)[4] Leading: 0.99 Lagging: 0.99	159 x Vestas 2.0 MW (VC200453400)[4] Leading: 0.99 Lagging: 0.99	45 x GE 3.4 MW (REGCA1)[4] Leading: 0.90 Lagging: 0.90	43 x GE 3.4 MW (REGCA1)[4] Leading: 0.90 Lagging: 0.90	45 x GE 3.4 MW (REGCA1)[4] Leading: 0.90 Lagging: 0.90	43 x GE 3.4 MW (REGCA1)[4] Leading: 0.90 Lagging: 0.90

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

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

SPP determined that power flow should not be performed based on the POI MW injection decrease of 0.99% compared to the DISIS-2017-002 power flow models (GEN-2016-119 dispatched to 100%). However, SPP determined that the change in turbine manufacturer from Vestas to GE 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 Siemens PTI PSS/E[1] 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-2016-119 project needed a 46 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 58.4 MVAr found using the existing DISIS-2017-002 model. 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 stability model modified for short circuit analysis. The results from the short circuit analysis with the updated topology showed that the maximum GEN-2016-119 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2016-119 POI was no greater than 2.4 kA. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-119 generator online were below 53 kA. There were several buses with a maximum three-phase fault current of over 40 kA. These buses are highlighted in Appendix B.

The dynamic stability analysis was performed using Siemens PTI PSS/E version 34.8 software for the two modified study models: 2025 Summer Peak and 2025 Winter Peak. 46 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 several existing base case issues found in the case with the GEN-2016-119 modification and in the original DISIS-2017-002 case. These issues were not attributed to the GEN-2016-119 modification request and are detailed in Appendix D.

[1] Power System Simulator for Engineering

There were no damping or voltage recovery violations attributed to the GEN-2016-119 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.

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-2016-119. 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 Siemens 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 model 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

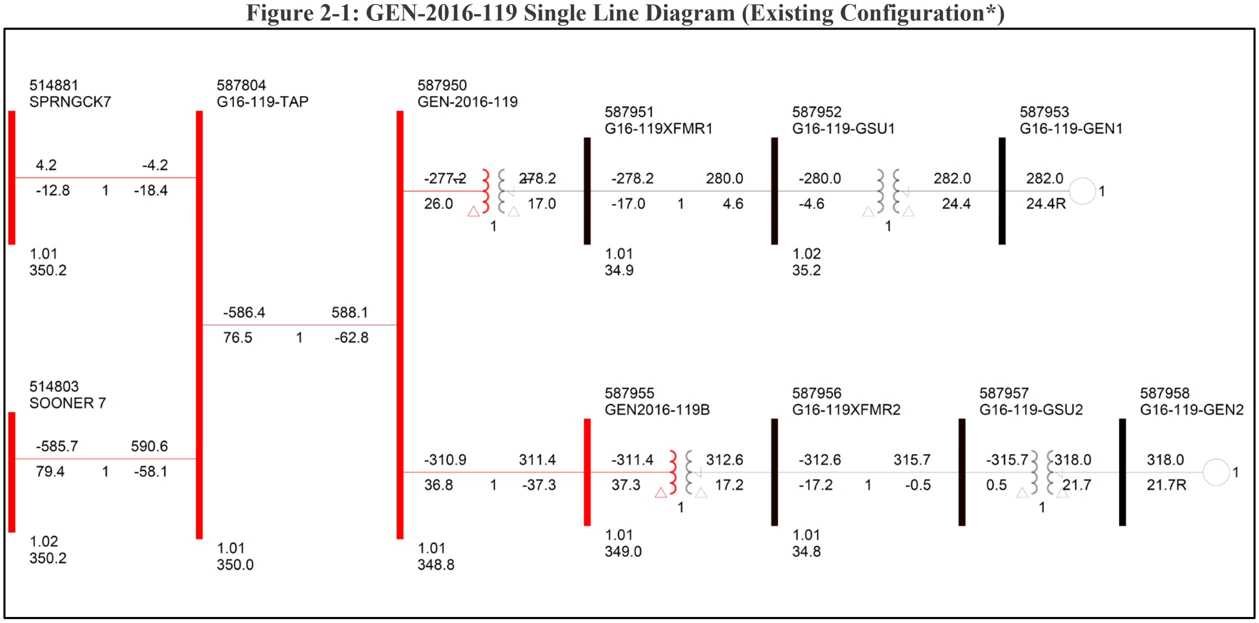
The GEN-2016-119 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a Point of Interconnection (POI) on the Spring Creek to Sooner 345 kV line. At the time of report posting, GEN-2016-119 is an active Interconnection Request with a queue status of "IA FULLY EXECUTED/ON SCHEDULE." GEN-2016-119 is a wind farm with a maximum summer and winter queue capacity of 600 MW with Energy Resource Interconnection Service (ERIS).

The GEN-2016-119 project is currently in the DISIS-2016-002 cluster. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2016-119 configuration using the DISIS-2017-002 stability models. The GEN-2016-119 project interconnects in the Oklahoma Gas & Electric (OKGE) control area with a capacity of 600 MW as shown in Table 2-1 below.

Table 2-1: GEN-2016-119 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2016-119	Tap on Spring Creek 345 kV (514881) to Sooner 345 kV (514803) (G16-119-TAP 587804)	300 x Vestas 2.0 MW	600

Figure 2-1: GEN-2016-119 Single Line Diagram (Existing Configuration*)



*based on the DISIS-2017-002 stability models

This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2016-119 to a turbine configuration of 176 x GE 3.43 MW for a total capacity of 603.68 MW. This generating capacity for GEN-2016-119 (603.68 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 600 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, generation interconnection line, and main substation transformers. Figure 2-2 shows the power flow model single line diagram for the GEN-2016-119 modification. The existing and modified configurations for GEN-2016-119 are shown in Table 2-2.

Figure 2-2: GEN-2016-119 Single Line Diagram (Modification Configuration)

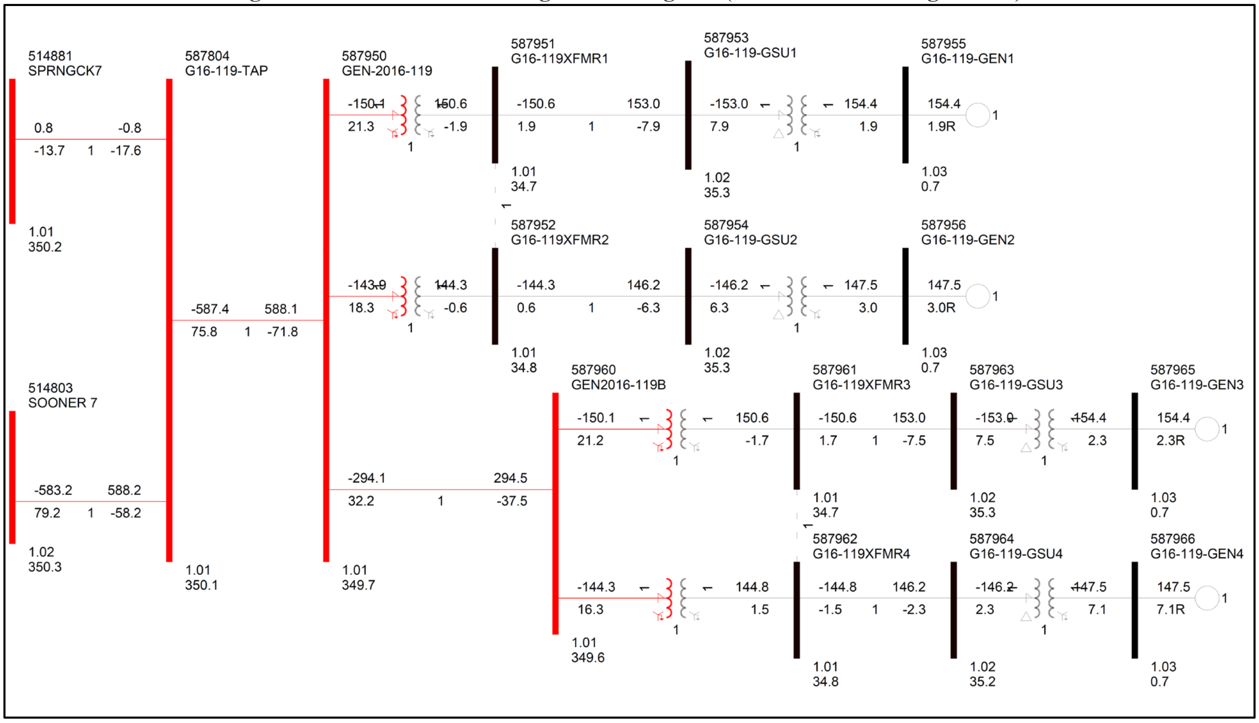


Table 2-2: GEN-2016-119 Modification Request

Facility	Existing Configuration		Modification Configuration			
Point of Interconnection	Spring Creek 345 kV (514881) to Sooner 345 kV (514803) (G16-119-TAP 587804)		Spring Creek 345 kV (514881) to Sooner 345 kV (514803) (G16-119-TAP 587804)			
Configuration/Capacity	300 x Vestas 2.0 MW = 600 MW		176 x GE 3.43 MW = 603.68 MW POI limited to 600 MW			
Generation Interconnection Line	G16-119-TAP to GEN-2016-119:	GEN-2016-119 to GEN2016-119B:	G16-119-TAP to GEN-2016-119:		GEN-2016-119 to GEN2016-119B:	
	Length = 18.7 miles R = 0.000500 pu X = 0.009040 pu B = 0.167440 pu Rating = 0 MVA	Length = 5.3 miles R = 0.000520 pu X = 0.003370 pu B = 0.035690 pu Rating = 0 MVA	Length = 5.87 miles R = 0.000193 pu X = 0.002772 pu B = 0.052994 pu Rating [A/B] = 1395/1543 MVA		Length = 10.53 miles R = 0.000452 pu X = 0.005047 pu B = 0.093546 pu Rating [A/B] = 1168/1288 MVA	
Main Substation Transformer[1]	X = 12.247%, R = 0.278%, Winding MVA = 216 MVA, Rating MVA = 360 MVA	X = 12.247%, R = 0.278%, Winding MVA = 216 MVA, Rating MVA = 360 MVA	X = 9.802%, R = 0.238%, Winding MVA = 113 MVA, Rating MVA = 189 MVA	X = 9.802%, R = 0.238%, Winding MVA = 113 MVA, Rating MVA = 189 MVA	X = 9.802%, R = 0.238%, Winding MVA = 113 MVA, Rating MVA = 189 MVA	X = 9.802%, R = 0.238%, Winding MVA = 113 MVA, Rating MVA = 189 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 141	Gen 2 Equivalent Qty: 159	Gen 1 Equivalent Qty: 45	Gen 2 Equivalent Qty: 43	Gen 3 Equivalent Qty: 45	Gen 4 Equivalent Qty: 43
	X = 7.759%, R = 0.799%, Winding MVA = 296.1 MVA, Rating MVA = 296.1 MVA	X = 7.759%, R = 0.799%, Winding MVA = 333.9 MVA, Rating MVA = 333.9 MVA	X = 7.484%, R = 0.998%, Winding MVA = 171.495 MVA, Rating MVA[2] = 171.5 MVA	X = 7.484%, R = 0.998%, Winding MVA = 163.873 MVA, Rating MVA[2] = 163.9 MVA	X = 7.484%, R = 0.998%, Winding MVA = 171.495 MVA, Rating MVA[2] = 171.5 MVA	X = 7.484%, R = 0.998%, Winding MVA = 163.873 MVA, Rating MVA[2] = 163.9 MVA
Equivalent Collector Line[3]	R = 0.002300 pu X = 0.003700 pu B = 0.147880 pu	R = 0.003200 pu X = 0.005100 pu B = 0.219790 pu	R = 0.010863 pu X = 0.012468 pu B = 0.085781 pu	R = 0.009558 pu X = 0.009343 pu B = 0.074332 pu	R = 0.010967 pu X = 0.014691 pu B = 0.087661 pu	R = 0.007141 pu X = 0.007362 pu B = 0.051911 pu
Generator Dynamic Model[4] & Power Factor	141 x Vestas 2.0 MW (VC200453400)[4] Leading: 0.99 Lagging: 0.99	159 x Vestas 2.0 MW (VC200453400)[4] Leading: 0.99 Lagging: 0.99	45 x GE 3.4 MW (REGCA1)[4] Leading: 0.90 Lagging: 0.90	43 x GE 3.4 MW (REGCA1)[4] Leading: 0.90 Lagging: 0.90	45 x GE 3.4 MW (REGCA1)[4] Leading: 0.90 Lagging: 0.90	43 x GE 3.4 MW (REGCA1)[4] Leading: 0.90 Lagging: 0.90

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 model configuration to the requested modifications for GEN-2016-119. The percentage change in the POI injection was then evaluated. If the MW percentage 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 0.99%) in the real power output at the POI between the studied DISIS-2017-002 power flow model configuration (GEN-2016-119 dispatched to 100%) and requested modification shown in Table 3-1.

Table 3-1: GEN-2016-119 POI Injection Comparison

Interconnection Request	Existing POI Injection (MW)	Modification POI Injection (MW)	POI Injection Difference %
GEN-2016-119	593.3	587.4	-0.99%

3.2 Turbine Parameters Comparison

SPP determined that short circuit and dynamic stability analyses were required because of the turbine change from Vestas to GE turbines. 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 already deemed 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.

4.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2016-119 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-2016-119 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-2016-119 project needed approximately 46 MVAr of compensation at its project substation to reduce the POI MVAr to zero. This is a decrease from the 58.4 MVAr found using the existing DISIS-2017-002 model. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the existing DISIS-2017-002 model. Figure 4-2 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-2016-119 are shown in Table 4-1.

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.

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

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)	
			25SP	25WP
GEN-2016-119	587804	G16-119-TAP 345 kV	46	46

Figure 4-1: GEN-2016-119 Single Line Diagram w/ Charging Current Compensation (Existing)

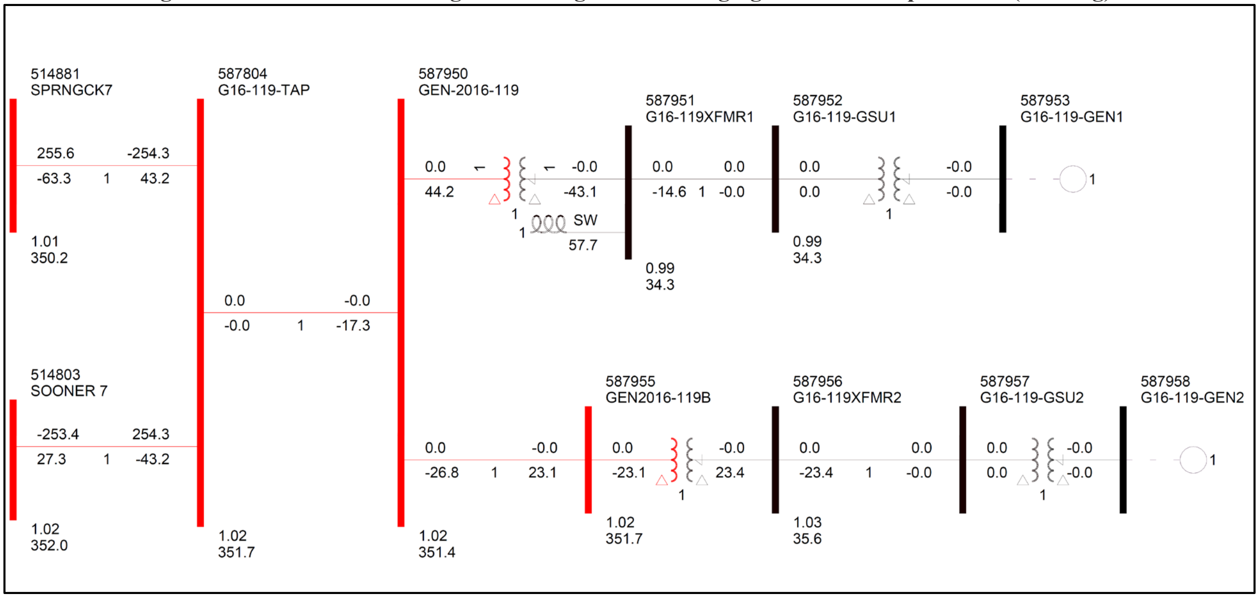
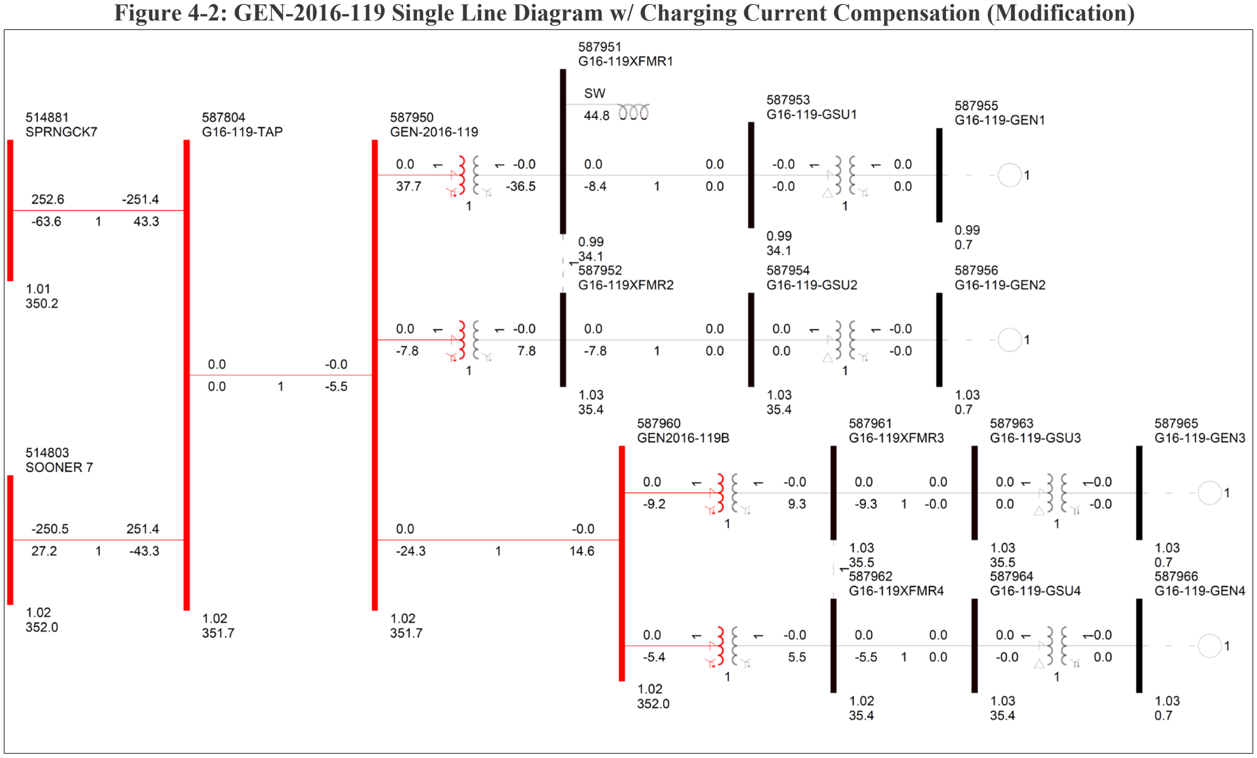


Figure 4-2: GEN-2016-119 Single Line Diagram w/ Charging Current Compensation (Modification)



5.0 Short Circuit Analysis

A short circuit study was performed using the 25SP model for GEN-2016-119. The detailed results of the short circuit analysis are provided in Appendix B.

5.1 Methodology

The short circuit analysis included applying a three-phase fault on buses up to 5 levels away from the 345 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-2016-119 online.

Aneden created a short circuit model using the 2025 Summer Peak DISIS-2017-002 stability study model by adjusting the GEN-2016-119 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#			
	587955	587956	587966	587965
Machine MVA Base	171.49	163.87	163.87	171.49
R (pu)	0.0	0.0	0.0	0.0
X'' (pu)	0.2	0.2	0.2	0.2

*pu values based on Machine MVA Base

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-2016-119 POI bus (G16-119-TAP 587804) fault current magnitudes are provided in Table 5-2 showing a maximum fault current of 16.85 kA with the GEN-2016-119 project online. Table 5-3 shows the maximum fault current magnitudes and fault current increases with the GEN-2016-119 project online.

The maximum fault current calculated within 5 buses of the GEN-2016-119 POI (including the POI bus) was less than 53 kA for the 25SP model. There were several buses with a maximum three-phase fault current of over 40 kA. These buses are highlighted in Appendix B. The maximum GEN-2016-119 contribution to three-phase fault current was about 16.7% and 2.4 kA.

Table 5-2: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
25SP	14.44	16.85	2.40	16.7%

Table 5-3: 25SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	17.6	0.00	0.0%
138	52.6	0.25	0.6%
161	16.7	0.00	0.0%
345	36.5	2.40	16.7%
Max	**52.6**	**2.40**	**16.7%**

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-2016-119. 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 existing base case issues and 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-2016-119 configuration of 176 x GE 3.43 MW (REGCA1). This stability analysis was performed using PTI's PSS/E version 34.8 software.

The modifications requested for the GEN-2016-119 project were used to create modified stability models 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-2016-119 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 GEN-2017-168 (761168) and GEN-2017-121 (761841 & 761844) voltage relays were disabled after observing the generators inappropriately tripping during initial three phase fault simulations with the existing DISIS-2017-002 model.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2016-119 and other current and prior queued projects in their cluster group[2]. In addition, voltages of five (5) buses away from the POI of GEN-2016-119 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 330 (AECI), 515 (SWPA), 520 (AEPW), 523 (GRDA), 524 (OKGE), 525 (WFEC), 527 (OMPA), and 534 (SUNC) 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-2016-119 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 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.

[2] Based on the DISIS-2017-002 Cluster Groups

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT01-3PH	P1	3 phase fault on the WEKIWA-7 (509755) to SOONER 7 (514803) 345 kV line CKT 1, near WEKIWA-7. a. Apply fault at the WEKIWA-7 345 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.
FLT04-3PH	P1	3 phase fault on the WOODRNG7 (514715) to PINTAIL7 (516010) 345 kV line CKT 1, near WOODRNG7. a. Apply fault at the WOODRNG7 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.
FLT9001-3PH	P1	3 phase fault on the G16-119-TAP (587804) to SOONER 7 (514803) 345 kV line CKT 1, near G16-119-TAP. a. Apply fault at the G16-119-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.
FLT9002-3PH	P1	3 phase fault on the G16-119-TAP (587804) to SPRNGCK7 (514881) 345 kV line CKT 1, near G16-119-TAP. a. Apply fault at the G16-119-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.
FLT9003-3PH	P1	3 phase fault on the SPRNGCK7 (514881) to NORTWST7 (514880) 345 kV line CKT 1, near SPRNGCK7. a. Apply fault at the SPRNGCK7 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.
FLT9004-3PH	P1	3 phase fault on the SOONER 7 (514803) to THUNDER7 (515894) 345 kV line CKT 1, near SOONER 7. a. Apply fault at the SOONER 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator THNDRG21 (515887)** **Trip generator THNDRG11 (515886)** 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.
FLT9005-3PH	P1	3 phase fault on the SOONER 7 (514803) to WEKIWA-7 (509755) 345 kV line CKT 1, near SOONER 7. a. Apply fault at the SOONER 7 345 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.
FLT9006-3PH	P1	3 phase fault on the SOONER 7 (514803) to G15-066T (560056) 345 kV line CKT 1, near SOONER 7. a. Apply fault at the SOONER 7 345 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.
FLT9007-3PH	P1	3 phase fault on the SOONER 7 (514803) to PINTAIL7 (516010) 345 kV line CKT 1, near SOONER 7. a. Apply fault at the SOONER 7 345 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.
FLT9008-3PH	P1	3 phase fault on the SOONER 7 (514803) to RANCHRD7 (515576) 345 kV line CKT 1, near SOONER 7. a. Apply fault at the SOONER 7 345 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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9009-3PH	P1	3 phase fault on the SOONER 345 kV (514803) / 20 kV (514806) XFMR CKT 1, near SOONER 7 345 kV. a. Apply fault at the SOONER 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer. **Trip generator SOONER2G (514806)**
FLT9010-3PH	P1	3 phase fault on the SOONER5 345 kV (514803) / 138 kV (514802)/ 13.8 kV (515760) XFMR CKT 1, near SOONER 7 345 kV. a. Apply fault at the SOONER 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9011-3PH	P1	3 phase fault on the SCGSGSU2 345 kV (514881) / 13.8 kV (514883) XFMR CKT 1, near SPRNGCK7 345 kV. a. Apply fault at the SPRNGCK7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer. **Trip generator SPGCK3&4 (514883)**
FLT9012-3PH	P1	3 phase fault on the SCGSGSU1 345 kV (514881) / 13.8 kV (514882) XFMR CKT 1, near SPRNGCK7 345 kV. a. Apply fault at the SPRNGCK7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer. **Trip generator SPGCK1&2 (514882)**
FLT9013-3PH	P1	3 phase fault on the NORTWST7 (514880) to ARCADIA7 (514908) 345 kV line CKT 1, near NORTWST7. a. Apply fault at the NORTWST7 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 NORTWST2 345 kV (514880) / 138 kV (514879)/ 13.8 kV (515742) XFMR CKT 1, near NORTWST7 345 kV. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9015-3PH	P1	3 phase fault on the NORTWST7 (514880) to CIMARON7 (514901) 345 kV line CKT 1, near NORTWST7. a. Apply fault at the NORTWST7 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 NORTWST7 (514880) to MATHWSN7 (515497) 345 kV line CKT 1, near NORTWST7. a. Apply fault at the NORTWST7 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 RANCHRD7 (515576) to FRNT2WD7 (516066) 345 kV line CKT 1, near RANCHRD7. a. Apply fault at the RANCHRD7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator FRNT2G11 (516060)** **Trip generator FRNT2G21 (516061)** 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 RANCHRD7 (515576) to FRNT2WND7 (515688) 345 kV line CKT 1, near RANCHRD7. a. Apply fault at the RANCHRD7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator FRNTWDG1 (516691)** 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.
FLT9019-3PH	P1	3 phase fault on the RANCHRD7 (515576) to OMCDLEC7 (529200) 345 kV line CKT 1, near RANCHRD7. a. Apply fault at the RANCHRD7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator OMCDLEC1 (529201)** 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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9020-3PH	P1	3 phase fault on the RANCHRD7 (515576) to OPENSKY7 (515621) 345 kV line CKT 1, near RANCHRD7. a. Apply fault at the RANCHRD7 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.
FLT9021-3PH	P1	3 phase fault on the PINTAIL7 (516010) to KINGWD 7 (516019) 345 kV line CKT Z1, near PINTAIL7. a. Apply fault at the PINTAIL7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator KNGWDG21 (516014)** **Trip generator KNGWDG11 (516013)** 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.
FLT9022-3PH	P1	3 phase fault on the PINTAIL7 (516010) to WOODRNG7 (514715) 345 kV line CKT 1, near PINTAIL7. a. Apply fault at the PINTAIL7 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.
FLT9023-3PH	P1	3 phase fault on the G15-066T (560056) to CLEVLND7 (512694) 345 kV line CKT 1, near G15-066T. a. Apply fault at the G15-066T 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 G15-066T (560056) to GEN-2015-066 (585040) 345 kV line CKT 1, near G15-066T. a. Apply fault at the G15-066T 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G15-066-GEN1 (563022)** 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.
FLT9025-3PH	P1	3 phase fault on the WEKIWA 345 kV (509755) / 138 kV (509757)/ 34.5 kV (509879) XFMR CKT 1, near WEKIWA-7 345 kV. a. Apply fault at the WEKIWA-7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9026-3PH	P1	3 phase fault on the WEKIWA-7 (509755) to SAPLPRD7 (509870) 345 kV line CKT 1, near WEKIWA-7. a. Apply fault at the WEKIWA-7 345 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.
FLT9027-3PH	P1	3 phase fault on the WEKIWA-7 (509755) to T.NO.-7 (509852) 345 kV line CKT 1, near WEKIWA-7. a. Apply fault at the WEKIWA-7 345 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.
FLT9013-PO1	P6	**PRIOR OUTAGE of G16-119-TAP (587804) to SOONER 7 (514803) 345 kV line CKT 1;** 3 phase fault on the NORTWST7 (514880) to ARCADIA7 (514908) 345 kV line CKT 1, near NORTWST7. a. Apply fault at the NORTWST7 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-PO1	P6	**PRIOR OUTAGE of G16-119-TAP (587804) to SOONER 7 (514803) 345 kV line CKT 1;** 3 phase fault on the NORTWST2 345 kV (514880) / 138 kV (514879)/ 13.8 kV (515742) XFMR CKT 1, near NORTWST7 345 kV. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9015-PO1	P6	**PRIOR OUTAGE of G16-119-TAP (587804) to SOONER 7 (514803) 345 kV line CKT 1;** 3 phase fault on the NORTWST7 (514880) to CIMARON7 (514901) 345 kV line CKT 1, near NORTWST7. a. Apply fault at the NORTWST7 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-PO1	P6	**PRIOR OUTAGE of G16-119-TAP (587804) to SOONER 7 (514803) 345 kV line CKT 1;** 3 phase fault on the NORTWST7 (514880) to MATHWSN7 (515497) 345 kV line CKT 1, near NORTWST7. a. Apply fault at the NORTWST7 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.
FLT9004-PO2	P6	**PRIOR OUTAGE of SPRNGCK7 (514881) to NORTWST7 (514880) 345 kV line CKT 1;** 3 phase fault on the SOONER 7 (514803) to THUNDER7 (515894) 345 kV line CKT 1, near SOONER 7. a. Apply fault at the SOONER 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator THNDRG21 (515887)** **Trip generator THNDRG11 (515886)** 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.
FLT9005-PO2	P6	**PRIOR OUTAGE of SPRNGCK7 (514881) to NORTWST7 (514880) 345 kV line CKT 1;** 3 phase fault on the SOONER 7 (514803) to WEKIWA-7 (509755) 345 kV line CKT 1, near SOONER 7. a. Apply fault at the SOONER 7 345 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.
FLT9006-PO2	P6	**PRIOR OUTAGE of SPRNGCK7 (514881) to NORTWST7 (514880) 345 kV line CKT 1;** 3 phase fault on the SOONER 7 (514803) to G15-066T (560056) 345 kV line CKT 1, near SOONER 7. a. Apply fault at the SOONER 7 345 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.
FLT9007-PO2	P6	**PRIOR OUTAGE of SPRNGCK7 (514881) to NORTWST7 (514880) 345 kV line CKT 1;** 3 phase fault on the SOONER 7 (514803) to PINTAIL7 (516010) 345 kV line CKT 1, near SOONER 7. a. Apply fault at the SOONER 7 345 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.
FLT9008-PO2	P6	**PRIOR OUTAGE of SPRNGCK7 (514881) to NORTWST7 (514880) 345 kV line CKT 1;** 3 phase fault on the SOONER 7 (514803) to RANCHRD7 (515576) 345 kV line CKT 1, near SOONER 7. a. Apply fault at the SOONER 7 345 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.
FLT9009-PO2	P6	**PRIOR OUTAGE of SPRNGCK7 (514881) to NORTWST7 (514880) 345 kV line CKT 1;** 3 phase fault on the SOONER 345 kV (514803) / 20 kV (514806) XFMR CKT 1, near SOONER 7 345 kV. a. Apply fault at the SOONER 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer. **Trip generator SOONER2G (514806)**
FLT9010-PO2	P6	**PRIOR OUTAGE of SPRNGCK7 (514881) to NORTWST7 (514880) 345 kV line CKT 1;** 3 phase fault on the SOONER5 345 kV (514803) / 138 kV (514802)/ 13.8 kV (515760) XFMR CKT 1, near SOONER 7 345 kV. a. Apply fault at the SOONER 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1001-SB	P4	**Stuck Breaker on SPRNGCK7 (514881) 345kV bus.** a. Apply single-phase fault at SPRNGCK7 (514881) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the SPRNGCK7 (514881) to G16-119-TAP (587804) 345 kV line CKT 1. d. Trip the SPRNGCK7 (514881) to NORTWST7 (514880) 345 kV line CKT 1. **Trip generator SPGCK1&2 (514882)** **Trip generator SPGCK3&4 (514883)**
FLT1002-SB	P4	**Stuck Breaker on SPRNGCK7 (514881) 345kV bus.** a. Apply single-phase fault at SPRNGCK7 (514881) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the SPRNGCK7 (514881) to G16-119-TAP (587804) 345 kV line CKT 1. d. Trip the SCGSGSU2 345 kV (514881) / 13.8 kV (514883) XFMR CKT 1. e. Trip the SCGSGSU1 345 kV (514881) / 13.8 kV (514882) XFMR CKT 1. **Trip generator SPGCK1&2 (514882)** **Trip generator SPGCK3&4 (514883)**
FLT1003-SB	P4	**Stuck Breaker on SPRNGCK7 (514881) 345kV bus.** a. Apply single-phase fault at SPRNGCK7 (514881) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the SPRNGCK7 (514881) to NORTWST7 (514880) 345 kV line CKT 1. d. Trip the SCGSGSU2 345 kV (514881) / 13.8 kV (514883) XFMR CKT 1. e. Trip the SCGSGSU1 345 kV (514881) / 13.8 kV (514882) XFMR CKT 1. **Trip generator SPGCK1&2 (514882)** **Trip generator SPGCK3&4 (514883)**
FLT1004-SB	P4	**Stuck Breaker on SOONER7 (514803) 345kV bus.** a. Apply single-phase fault at SOONER7 (514803) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the SOONER 7 (514803) to THUNDER7 (515894) 345 kV line CKT 1. d. Trip the SOONER 7 (514803) to PINTAIL7 (516010) 345 kV line CKT 1. **Trip generator THNDRG21 (515887).** **Trip generator THNDRG11 (515886).**
FLT1005-SB	P4	**Stuck Breaker on SOONER7 (514803) 345kV bus.** a. Apply single-phase fault at SOONER7 (514803) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the SOONER 345 kV (514803) / 20 kV (514806) XFMR CKT 1. d. Trip the SOONER 7 (514803) to G16-119-TAP (587804) 345 kV line CKT 1 **Trip generator SOONER2G (514806)**
FLT1006-SB	P4	**Stuck Breaker on SOONER7 (514803) 345kV bus.** a. Apply single-phase fault at SOONER7 (514803) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the SOONER5 345 kV (514803) / 138 kV (514802)/ 13.8 kV (515760) XFMR CKT 1. d. Trip the SOONER 7 (514803) to WEKIWA-7 (509755) 345 kV line CKT 1

6.3 Results

Table 6-2 shows the relevant results of the fault events simulated for each of the modified cases. Existing DISIS base case issues are documented separately in Appendix D. The associated stability plots are also provided in Appendix D.

Table 6-2: GEN-2016-119 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
FLT04-3PH	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	Pass	Pass	Stable	Pass	Pass	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
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 Continued

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-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

The results of the dynamic stability analysis showed that there were several existing base case issues found in the original DISIS-2017-002 case and the case with the GEN-2016-119 modification. These issues were not attributed to the GEN-2016-119 modification request and detailed in Appendix D.

There were no damping or voltage recovery violations attributed to the GEN-2016-119 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-2016-119 (603.68 MW) exceeds the GIA Interconnection Service amount, 600 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-2016-119 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-2016-119 requested a Modification Request Impact Study to assess the impact of the turbine and facility change to 176 x GE 3.43 MW for a total capacity of 603.68 MW. This generating capacity for GEN-2016-119 (603.68 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 600 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, generation interconnection line, and main substation transformers.

SPP determined that power flow should not be performed based on the POI MW injection decrease of 0.99% compared to the DISIS-2017-002 power flow models (GEN-2016-119 dispatched to 100%). However, SPP determined that the change in turbine manufacturer from Vestas to GE required short circuit and dynamic stability analyses.

All analyses were performed using the Siemens 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-2016-119 project needed a 46 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 58.4 MVAr found using the existing DISIS-2017-002 model. 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 stability model modified for short circuit analysis. The results from the short circuit analysis with the updated topology showed that the maximum GEN-2016-119 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2016-119 POI was no greater than 2.4 kA. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-119 generator online were below 53 kA. There were several buses with a maximum three-phase fault current of over 40 kA. These buses are highlighted in Appendix B.

The dynamic stability analysis was performed using Siemens PTI PSS/E version 34.8 software for the two modified study models: 2025 Summer Peak and 2025 Winter Peak. 46 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 several existing base case issues found in the case with the GEN-2016-119 modification and in the original DISIS-2017-002 case. These issues were not attributed to the GEN-2016-119 modification request and are described in more detail in Appendix D.

There were no damping or voltage recovery violations attributed to the GEN-2016-119 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.

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Appendices

GEN-2016-119
Modification Request Impact Study

Date of Submittal

January 19, 2023

anedenconsulting.com

Appendix A

GEN-2016-119 Generator Dynamic Model

```
 // *************** GEN-2016-119 100% **************
//
// POI tap on Spring Creek - Sooner 345kV
//
// GE 3.4-140 3.43MW X 88 X 2 = 603.68MW
//
// Pmax=603.68 MW | Pgen=603.68 MW

587965 'REGCA1' 1       1
              0.20000E-01  3.00000       0.90000      0.50000      1.2300
              1.2000       0.1000        0.01000      -1.3000      0.20000E-01
              0.20000      999.00        -999.0       0.70000      /
587965 'REECA1' 1
              0            0             1            1            0             0
              -99.0000     99.0000       0.20000E-01  -0.0500      0.0500
              0.0000       1.0500        -1.0500      0.0000       0.1500
              0.0000       0.0000        0.50000E-01  0.4360       -0.4360
              1.1000       0.9000        0.0000       0.4100       1.0000
              60.000       0.0000        0.20000E-01  99.0000      -99.0000
              1.1200       0.40000E-01   1.5000       0.20000E-01  0.5000
              0.9900       0.9000        0.5400       1.1000       0.5400
              1.2500       1.2600        0.0000       0.0000       0.5000
              0.0000       0.9000        1.2300       1.0000       1.1070        /
587965 'WTDTA1' 1
              4.7400       0.0000        0.0100       1.8800       1.5000        /
587965 'WTPTA1' 1
              50.000       200.00        0.000        0.0000       0.0000
              0.3000       27.000        0.000        10.000       -10.00        /
587965 'WTARA1'  1
              0.70000E-02  10.0000       /
587965 'REPCTA1' 1
              587960       0             0            0            0             1            1
              0.50000      2.0000        1.0000       0.0200       0.2500
              0.7000       0.0000        0.0000       0.0000       0.100
              -0.100       0.0000        0.0000       0.4360       -0.4360
              1.2000       0.1400        0.1000       -6.00E-04    6.00E-04
              999.0000     -999.0000     999.0000     -999         0.2500
              20.0000      20.0000       /
587965  'WTTQA1'  1      1
              0.0100       0.1000        0.1000       60.000       1.2000        0.40000E-01   0.2000
              0.6900       0.4000        0.7800       0.6000       0.9800        0.7400
              1.2000       0.0000        /

58796521 'FRQTPAT'  587965 587965 '1'    55.0 65.0  0.10   0.08 /
58796522 'FRQTPAT'  587965 587965 '1'    57.0 63.0  60.0   0.08 /

58796500  'VTGTPAT'
         587965  587965  '1 '
       0.30000       5.0000      0.55000      0.80000E-01/
58796501  'VTGTPAT'
         587965  587965  '1 '
```

```
        0.40000      5.0000      1.0000      0.80000E-01/
58796502  'VTGTPAT'
          587965  587965  '1 '
        0.50000      5.0000      1.5000      0.80000E-01/
58796503  'VTGTPAT'
          587965  587965  '1 '
        0.60000      5.0000      2.00000      0.80000E-01/
58796504  'VTGTPAT'
          587965  587965  '1 '
        0.70000      5.0000      2.50000      0.80000E-01/
58796505  'VTGTPAT'
          587965  587965  '1 '
        0.75000      5.0000      3.00000      0.80000E-01/
58796506  'VTGTPAT'
          587965  587965  '1 '
        0.85000      5.0000      10.0000      0.80000E-01/
58796507  'VTGTPAT'
          587965  587965  '1 '
        0.90000      5.0000      600.00      0.80000E-01/
58796508  'VTGTPAT'
          587965  587965  '1 '
        0.00000      1.120      300.00      0.80000E-01/
58796509  'VTGTPAT'
          587965  587965  '1 '
        0.00000      1.150      30.000      0.80000E-01/
58796510  'VTGTPAT'
          587965  587965  '1 '
        0.00000      1.200      2.5000      0.80000E-01/
58796511  'VTGTPAT'
          587965  587965  '1 '
        0.00000      1.3000      1.0000      0.80000E-01/
58796512  'VTGTPAT'
          587965  587965  '1 '
        0.00000      1.3500      0.300      0.80000E-01/
58796513  'VTGTPAT'
          587965  587965  '1 '
        0.00000      1.5000      0.0300      0.80000E-01/
58796514  'VTGTPAT'
          587965  587965  '1 '
        0.00000      1.6000      0.0100      0.80000E-01/


587966 'REGCA1' 1       1
              0.20000E-01  3.00000      0.90000      0.50000      1.2300
              1.2000      0.1000      0.01000      -1.3000      0.20000E-01
              0.20000      999.00      -999.0      0.70000      /
587966 'REECA1' 1
              0          0          1          1          0          0
              -99.0000     99.0000      0.20000E-01  -0.0500      0.0500
              0.0000      1.0500      -1.0500      0.0000      0.1500
              0.0000      0.0000      0.50000E-01  0.4360      -0.4360
```

```
          1.1000    0.9000     0.0000    0.4100    1.0000
          60.000    0.0000     0.20000E-01  99.0000   -99.0000
          1.1200    0.40000E-01  1.5000    0.20000E-01  0.5000
          0.9900    0.9000     0.5400    1.1000    0.5400
          1.2500    1.2600     0.0000    0.0000    0.5000
          0.0000    0.9000     1.2300    1.0000    1.1070     /
587966 'WTDTA1' 1
          4.7400    0.0000     0.0100    1.8800    1.5000     /
587966 'WTPTA1' 1
          50.000    200.00     0.000     0.0000    0.0000
          0.3000    27.000     0.000     10.000    -10.00     /
587966 'WTARA1'  1
          0.70000E-02  10.0000    /
587966 'REPCTA1' 1
          587960      0        0        0        0        1        1
          0.50000   2.0000     1.0000    0.0200    0.2500
          0.7000    0.0000     0.0000    0.0000    0.100
          -0.100    0.0000     0.0000    0.4360    -0.4360
          1.2000    0.1400     0.1000    -6.00E-04  6.00E-04
          999.0000   -999.0000   999.0000   -999     0.2500
          20.0000   20.0000    /
587966  'WTTQA1'  1   1
          0.0100    0.1000     0.1000    60.000    1.2000     0.40000E-01  0.2000
          0.6900    0.4000     0.7800    0.6000    0.9800     0.7400
          1.2000    0.0000     /

58796621 'FRQTPAT'  587966 587966 '1'   55.0 65.0  0.10  0.08 /
58796622 'FRQTPAT'  587966 587966 '1'   57.0 63.0  60.0  0.08 /

58796600  'VTGTPAT'
       587966  587966  '1 '
      0.30000    5.0000    0.55000    0.80000E-01/
58796601  'VTGTPAT'
       587966  587966  '1 '
      0.40000    5.0000    1.0000    0.80000E-01/
58796602  'VTGTPAT'
       587966  587966  '1 '
      0.50000    5.0000    1.5000    0.80000E-01/
58796603  'VTGTPAT'
       587966  587966  '1 '
      0.60000    5.0000    2.00000    0.80000E-01/
58796604  'VTGTPAT'
       587966  587966  '1 '
      0.70000    5.0000    2.50000    0.80000E-01/
58796605  'VTGTPAT'
       587966  587966  '1 '
      0.75000    5.0000    3.00000    0.80000E-01/
58796606  'VTGTPAT'
       587966  587966  '1 '
      0.85000    5.0000    10.0000    0.80000E-01/
58796607  'VTGTPAT'
```

```
     587966  587966  '1 '
   0.90000      5.0000      600.00      0.80000E-01/
58796608  'VTGTPAT'
     587966  587966  '1 '
   0.00000      1.120      300.00      0.80000E-01/
58796609  'VTGTPAT'
     587966  587966  '1 '
   0.00000      1.150      30.000      0.80000E-01/
58796610  'VTGTPAT'
     587966  587966  '1 '
   0.00000      1.200      2.5000      0.80000E-01/
58796611  'VTGTPAT'
     587966  587966  '1 '
   0.00000      1.3000      1.0000      0.80000E-01/
58796612  'VTGTPAT'
     587966  587966  '1 '
   0.00000      1.3500      0.300      0.80000E-01/
58796613  'VTGTPAT'
     587966  587966  '1 '
   0.00000      1.5000      0.0300      0.80000E-01/
58796614  'VTGTPAT'
     587966  587966  '1 '
   0.00000      1.6000      0.0100      0.80000E-01/


587956 'REGCA1' 1      1
        0.20000E-01  3.00000      0.90000      0.50000      1.2300
        1.2000      0.1000      0.01000      -1.3000      0.20000E-01
        0.20000      999.00      -999.0      0.70000      /
587956 'REECA1' 1
        0           0           1           1           0           0
        -99.0000     99.0000      0.20000E-01  -0.0500      0.0500
        0.0000      1.0500      -1.0500      0.0000      0.1500
        0.0000      0.0000      0.50000E-01  0.4360      -0.4360
        1.1000      0.9000      0.0000      0.4100      1.0000
        60.000      0.0000      0.20000E-01  99.0000      -99.0000
        1.1200      0.40000E-01   1.5000      0.20000E-01  0.5000
        0.9900      0.9000      0.5400      1.1000      0.5400
        1.2500      1.2600      0.0000      0.0000      0.5000
        0.0000      0.9000      1.2300      1.0000      1.1070      /
587956 'WTDTA1' 1
        4.7400      0.0000      0.0100      1.8800      1.5000      /
587956 'WTPTA1' 1
        50.000      200.00      0.000      0.0000      0.0000
        0.3000      27.000      0.000      10.000      -10.00      /
587956 'WTARA1'  1
        0.70000E-02  10.0000      /
587956 'REPCTA1' 1
        587950          0           0           0           0           1           1
        0.50000      2.0000      1.0000      0.0200      0.2500
```

```
          0.7000     0.0000     0.0000     0.0000     0.100
          -0.100     0.0000     0.0000     0.4360     -0.4360
          1.2000     0.1400     0.1000     -6.00E-04  6.00E-04
          999.0000   -999.0000  999.0000   -999       0.2500
          20.0000    20.0000    /
587956  'WTTQA1'  1    1
          0.0100     0.1000     0.1000     60.000     1.2000     0.40000E-01   0.2000
          0.6900     0.4000     0.7800     0.6000     0.9800     0.7400
          1.2000     0.0000     /

58795621 'FRQTPAT'  587956 587956 '1'    55.0 65.0  0.10   0.08 /
58795622 'FRQTPAT'  587956 587956 '1'    57.0 63.0  60.0   0.08 /

58795600  'VTGTPAT'
      587956  587956  '1 '
     0.30000     5.0000     0.55000     0.80000E-01/
58795601  'VTGTPAT'
      587956  587956  '1 '
     0.40000     5.0000     1.0000     0.80000E-01/
58795602  'VTGTPAT'
      587956  587956  '1 '
     0.50000     5.0000     1.5000     0.80000E-01/
58795603  'VTGTPAT'
      587956  587956  '1 '
     0.60000     5.0000     2.00000     0.80000E-01/
58795604  'VTGTPAT'
      587956  587956  '1 '
     0.70000     5.0000     2.50000     0.80000E-01/
58795605  'VTGTPAT'
      587956  587956  '1 '
     0.75000     5.0000     3.00000     0.80000E-01/
58795606  'VTGTPAT'
      587956  587956  '1 '
     0.85000     5.0000     10.0000     0.80000E-01/
58795607  'VTGTPAT'
      587956  587956  '1 '
     0.90000     5.0000     600.00     0.80000E-01/
58795608  'VTGTPAT'
      587956  587956  '1 '
     0.00000     1.120     300.00     0.80000E-01/
58795609  'VTGTPAT'
      587956  587956  '1 '
     0.00000     1.150     30.000     0.80000E-01/
58795610  'VTGTPAT'
      587956  587956  '1 '
     0.00000     1.200     2.5000     0.80000E-01/
58795611  'VTGTPAT'
      587956  587956  '1 '
     0.00000     1.3000     1.0000     0.80000E-01/
58795612  'VTGTPAT'
      587956  587956  '1 '
```

```
        0.00000      1.3500      0.300       0.80000E-01/
58795613  'VTGTPAT'
          587956  587956  '1 '
        0.00000      1.5000      0.0300      0.80000E-01/
58795614  'VTGTPAT'
          587956  587956  '1 '
        0.00000      1.6000      0.0100      0.80000E-01/


587955 'REGCA1' 1       1
                0.20000E-01  3.00000      0.90000      0.50000      1.2300
                1.2000       0.1000       0.01000      -1.3000      0.20000E-01
                0.20000      999.00       -999.0       0.70000      /
587955 'REECA1' 1
                0            0            1            1            0            0
                -99.0000     99.0000      0.20000E-01  -0.0500      0.0500
                0.0000       1.0500       -1.0500      0.0000       0.1500
                0.0000       0.0000       0.50000E-01  0.4360       -0.4360
                1.1000       0.9000       0.0000       0.4100       1.0000
                60.000       0.0000       0.20000E-01  99.0000      -99.0000
                1.1200       0.40000E-01  1.5000       0.20000E-01  0.5000
                0.9900       0.9000       0.5400       1.1000       0.5400
                1.2500       1.2600       0.0000       0.0000       0.5000
                0.0000       0.9000       1.2300       1.0000       1.1070       /
587955 'WTDTA1' 1
                4.7400       0.0000       0.0100       1.8800       1.5000       /
587955 'WTPTA1' 1
                50.000       200.00       0.000        0.0000       0.0000
                0.3000       27.000       0.000        10.000       -10.00       /
587955 'WTARA1'  1
                0.70000E-02  10.0000      /
587955 'REPCTA1' 1
                587950       0            0            0            0            1            1
                0.50000      2.0000       1.0000       0.0200       0.2500
                0.7000       0.0000       0.0000       0.0000       0.100
                -0.100       0.0000       0.0000       0.4360       -0.4360
                1.2000       0.1400       0.1000       -6.00E-04    6.00E-04
                999.0000     -999.0000    999.0000     -999         0.2500
                20.0000      20.0000      /
587955  'WTTQA1'  1      1
                0.0100       0.1000       0.1000       60.000       1.2000       0.40000E-01   0.2000
                0.6900       0.4000       0.7800       0.6000       0.9800       0.7400
                1.2000       0.0000       /

58795521 'FRQTPAT'  587955 587955 '1'    55.0 65.0  0.10   0.08 /
58795522 'FRQTPAT'  587955 587955 '1'    57.0 63.0  60.0   0.08 /

58795500  'VTGTPAT'
          587955  587955  '1 '
        0.30000      5.0000      0.55000      0.80000E-01/
58795501  'VTGTPAT'
```

```
     587955  587955  '1 '
    0.40000      5.0000      1.0000      0.80000E-01/
58795502  'VTGTPAT'
     587955  587955  '1 '
    0.50000      5.0000      1.5000      0.80000E-01/
58795503  'VTGTPAT'
     587955  587955  '1 '
    0.60000      5.0000      2.00000      0.80000E-01/
58795504  'VTGTPAT'
     587955  587955  '1 '
    0.70000      5.0000      2.50000      0.80000E-01/
58795505  'VTGTPAT'
     587955  587955  '1 '
    0.75000      5.0000      3.00000      0.80000E-01/
58795506  'VTGTPAT'
     587955  587955  '1 '
    0.85000      5.0000      10.0000      0.80000E-01/
58795507  'VTGTPAT'
     587955  587955  '1 '
    0.90000      5.0000      600.00      0.80000E-01/
58795508  'VTGTPAT'
     587955  587955  '1 '
    0.00000      1.120      300.00      0.80000E-01/
58795509  'VTGTPAT'
     587955  587955  '1 '
    0.00000      1.150      30.000      0.80000E-01/
58795510  'VTGTPAT'
     587955  587955  '1 '
    0.00000      1.200      2.5000      0.80000E-01/
58795511  'VTGTPAT'
     587955  587955  '1 '
    0.00000      1.3000      1.0000      0.80000E-01/
58795512  'VTGTPAT'
     587955  587955  '1 '
    0.00000      1.3500      0.300      0.80000E-01/
58795513  'VTGTPAT'
     587955  587955  '1 '
    0.00000      1.5000      0.0300      0.80000E-01/
58795514  'VTGTPAT'
     587955  587955  '1 '
    0.00000      1.6000      0.0100      0.80000E-01/
```

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	%	587804	
514879	NORTWST4	138	524	569	45.365	45.115	0.250	0.55%	3	TRUE
514898	CIMARON4	138	524	569	46.366	46.247	0.119	0.26%	4	TRUE
514907	ARCADIA4	138	524	569	43.149	43.065	0.084	0.20%	4	TRUE
509773	RSS T1 4	138	520	546	51.659	51.630	0.029	0.06%	5	TRUE
509875	RSS T2 4	138	520	546	52.586	52.556	0.030	0.06%	5	TRUE
514929	PLVALLY4	138	524	569	46.548	46.489	0.059	0.13%	5	TRUE
515044	SEMINOL4	138	524	568	40.886	40.872	0.014	0.03%	5	TRUE
515461	RNDBARN4	138	524	569	40.920	40.844	0.076	0.19%	5	TRUE
587804	G16-119-TAP	345	524	566	16.846	14.442	2.404	16.65%	0	FALSE
514803	SOONER 7	345	524	566	29.357	28.360	0.997	3.52%	1	FALSE
514881	SPRNGCK7	345	524	569	24.153	23.480	0.673	2.87%	1	FALSE
509755	WEKIWA-7	345	520	546	22.218	22.144	0.074	0.33%	2	FALSE
514802	SOONER 4	138	524	566	31.974	31.858	0.116	0.36%	2	FALSE
514880	NORTWST7	345	524	569	34.234	33.679	0.555	1.65%	2	FALSE
515576	RANCHRD7	345	524	566	14.576	14.475	0.101	0.70%	2	FALSE
515894	THUNDER7	345	524	566	11.668	11.527	0.141	1.22%	2	FALSE
516010	PINTAIL7	345	524	566	17.397	17.228	0.169	0.98%	2	FALSE
560056	G15-066T	345	524	566	19.443	19.098	0.345	1.81%	2	FALSE
509757	WEKIWA-4	138	520	546	32.766	32.723	0.043	0.13%	3	FALSE
509852	T.NO.--7	345	520	546	23.876	23.808	0.068	0.29%	3	FALSE
509870	SAPLPRD7	345	520	546	22.704	22.668	0.036	0.16%	3	FALSE
512694	CLEVLND7	345	523	554	14.999	14.904	0.095	0.64%	3	FALSE
514704	MILLERT4	138	524	566	20.563	20.519	0.044	0.21%	3	FALSE
514707	PERRY 4	138	524	566	10.973	10.962	0.011	0.10%	3	FALSE
514715	WOODRNG7	345	524	566	20.634	20.518	0.116	0.57%	3	FALSE
514798	SNRPMPT4	138	524	566	20.610	20.566	0.044	0.21%	3	FALSE
514901	CIMARON7	345	524	569	36.539	36.254	0.285	0.79%	3	FALSE
514908	ARCADIA7	345	524	569	28.305	28.213	0.092	0.33%	3	FALSE
515447	MORISNT4	138	524	568	13.882	13.867	0.015	0.11%	3	FALSE
515497	MATHWSN7	345	524	566	34.588	34.280	0.308	0.90%	3	FALSE
515621	OPENSKY7	345	524	566	12.661	12.604	0.057	0.45%	3	FALSE
515688	FRNTWND7	345	524	566	11.813	11.750	0.063	0.54%	3	FALSE
516019	KINGWD 7	345	524	566	17.334	17.166	0.168	0.98%	3	FALSE
516066	FRNT2WD7	345	524	566	11.463	11.404	0.059	0.52%	3	FALSE
529200	OMCDLEC7	345	527	1513	14.547	14.447	0.100	0.69%	3	FALSE
585040	GEN-2015-066	345	524	566	19.249	18.912	0.337	1.78%	3	FALSE
505610	KEYSTON4	138	515	523	22.595	22.574	0.021	0.09%	4	FALSE
509782	R.S.S.-7	345	520	546	32.035	31.999	0.036	0.11%	4	FALSE
509812	SHEFFD-4	138	520	546	25.878	25.861	0.017	0.07%	4	FALSE
509823	WED-TAP4	138	520	546	19.111	19.100	0.011	0.06%	4	FALSE
509851	P&P WTP4	138	520	546	15.121	15.113	0.008	0.05%	4	FALSE
509871	SAPLPRD4	138	520	546	33.042	33.022	0.020	0.06%	4	FALSE
509895	T.NO.2-4	138	520	546	34.525	34.492	0.033	0.10%	4	FALSE
510406	N.E.S.-7	345	520	547	18.925	18.909	0.016	0.08%	4	FALSE
512726	SILVCTYGR4	138	523	558	15.544	15.532	0.012	0.08%	4	FALSE
512729	CLEVLND 4	138	523	554	16.628	16.602	0.026	0.16%	4	FALSE
513596	IGLOOV 7	345	523	555	19.728	19.721	0.007	0.04%	4	FALSE
514706	COWCRK 4	138	524	566	11.239	11.228	0.011	0.10%	4	FALSE
514714	WOODRNG4	138	524	566	19.942	19.916	0.026	0.13%	4	FALSE
514743	OSAGE 4	138	524	566	17.051	17.033	0.018	0.11%	4	FALSE
514799	SNRPMP 4	138	524	566	11.319	11.306	0.013	0.11%	4	FALSE
514801	MINCO 7	345	524	567	23.685	23.632	0.053	0.22%	4	FALSE
514825	KAYWIND7	345	524	566	12.626	12.569	0.057	0.45%	4	FALSE
514828	KETCHTP4	138	524	569	26.893	26.842	0.051	0.19%	4	FALSE
514854	BRADEN 4	138	524	569	32.073	31.967	0.106	0.33%	4	FALSE
514864	PIEDMNT4	138	524	569	22.722	22.668	0.054	0.24%	4	FALSE
514873	LNEOAK 4	138	524	569	27.390	27.311	0.079	0.29%	4	FALSE
514909	REDBUD 7	345	524	569	27.345	27.269	0.076	0.28%	4	FALSE
515006	MORRISN4	138	524	568	13.855	13.840	0.015	0.11%	4	FALSE
515011	STILWTR4	138	524	568	13.976	13.965	0.011	0.08%	4	FALSE
515045	SEMINOL7	345	524	568	28.539	28.510	0.029	0.10%	4	FALSE
515407	TATONGA7	345	524	566	17.583	17.552	0.031	0.18%	4	FALSE
515412	DMNCRKT4	138	524	566	13.889	13.872	0.017	0.12%	4	FALSE
515476	HUNTERS7	345	524	566	14.168	14.135	0.033	0.23%	4	FALSE
515610	FSHRTAP7	345	524	569	18.116	18.058	0.058	0.32%	4	FALSE
515875	REDNGTN7	345	524	566	18.685	18.600	0.085	0.46%	4	FALSE
515978	OTOETAP4	138	524	566	16.413	16.385	0.028	0.17%	4	FALSE
515990	SKELTON7	345	524	566	6.924	6.913	0.011	0.16%	4	FALSE
555234	NSUB345	345	524	569	27.213	27.145	0.068	0.25%	4	FALSE
560053	G15-052T	345	524	566	11.917	11.891	0.026	0.22%	4	FALSE
560389	GEN-2010-055	138	520	546	32.766	32.723	0.043	0.13%	4	FALSE
588190	GEN-2016-128	345	524	566	8.188	8.170	0.018	0.22%	4	FALSE
760032	GEN-2017-132	345	524	1	6.593	6.590	0.003	0.05%	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	%	587804	
762321	GEN-2017-164	345	524	1	11.767	11.731	0.036	0.31%	4	FALSE
900001	TRAVERSE3	345	524	566	6.974	6.966	0.008	0.11%	4	FALSE
300131	4FISHERTP	138	330	305	14.886	14.876	0.010	0.07%	5	FALSE
300138	4CLEVLND	138	330	305	16.628	16.602	0.026	0.16%	5	FALSE
300140	4SILVCTY	138	330	305	15.695	15.683	0.012	0.08%	5	FALSE
301011	4REDRCK	138	330	305	16.041	16.014	0.027	0.17%	5	FALSE
505609	KEYSTON5	161	515	523	7.089	7.087	0.002	0.03%	5	FALSE
509759	JENKS--4	138	520	546	25.432	25.423	0.009	0.04%	5	FALSE
509805	PP----W4	138	520	546	8.310	8.308	0.002	0.02%	5	FALSE
509807	ONETA--7	345	520	546	29.408	29.390	0.018	0.06%	5	FALSE
509815	S.S.---4	138	520	546	28.673	28.653	0.020	0.07%	5	FALSE
509817	T.NO.--4	138	520	546	34.579	34.547	0.032	0.09%	5	FALSE
509834	COGENT 7	345	520	546	29.692	29.662	0.030	0.10%	5	FALSE
509848	OAKSWTP4	138	520	546	24.857	24.848	0.009	0.04%	5	FALSE
509865	CARSONT4	138	520	546	11.906	11.902	0.004	0.03%	5	FALSE
509888	72ELWOD4	138	520	546	23.306	23.298	0.008	0.03%	5	FALSE
509896	DENV_WTAP4	138	520	546	27.947	27.929	0.018	0.06%	5	FALSE
510376	WEBBTAP4	138	520	547	7.954	7.952	0.002	0.03%	5	FALSE
510380	DELWARE7	345	520	547	11.562	11.558	0.004	0.03%	5	FALSE
510907	PITTSB-7	345	520	548	14.728	14.725	0.003	0.02%	5	FALSE
511425	TUTCONT4	138	520	549	10.393	10.390	0.003	0.03%	5	FALSE
512865	GREC TAP5	345	523	554	24.861	24.855	0.006	0.02%	5	FALSE
513593	IGLOOV1 5	161	523	555	16.684	16.682	0.002	0.01%	5	FALSE
513595	IGLOOV2 5	161	523	555	16.684	16.682	0.002	0.01%	5	FALSE
514705	COWCRK 2	69	524	566	4.044	4.043	0.001	0.02%	5	FALSE
514708	OTTER 4	138	524	566	8.783	8.778	0.005	0.06%	5	FALSE
514709	FRMNTAP4	138	524	566	18.632	18.611	0.021	0.11%	5	FALSE
514711	WAUKOTP4	138	524	566	16.138	16.123	0.015	0.09%	5	FALSE
514713	WRVALLY4	138	524	566	8.518	8.512	0.006	0.07%	5	FALSE
514733	MARSHL 4	138	524	566	8.405	8.401	0.004	0.05%	5	FALSE
514737	OTOE 4	138	524	566	16.367	16.339	0.028	0.17%	5	FALSE
514742	OSGE 2	69	524	566	17.602	17.597	0.005	0.03%	5	FALSE
514758	STDBEAR4	138	524	566	14.219	14.207	0.012	0.08%	5	FALSE
514761	WHEAGLE4	138	524	566	16.162	16.146	0.016	0.10%	5	FALSE
514770	MARLNDT4	138	524	566	11.125	11.117	0.008	0.07%	5	FALSE
514819	EL-RENO4	138	524	569	16.880	16.867	0.013	0.08%	5	FALSE
514820	JENSENT4	138	524	569	18.329	18.315	0.014	0.08%	5	FALSE
514827	CTNWOOD4	138	524	569	18.452	18.436	0.016	0.09%	5	FALSE
514834	KETCH 4	138	524	569	27.357	27.305	0.052	0.19%	5	FALSE
514851	QUAILCK4	138	524	569	29.885	29.810	0.075	0.25%	5	FALSE
514852	SLVRLAK4	138	524	569	33.418	33.322	0.096	0.29%	5	FALSE
514862	RICHRDS4	138	524	569	22.056	22.015	0.041	0.19%	5	FALSE
514863	HAYMAKR4	138	524	569	27.018	26.971	0.047	0.17%	5	FALSE
514894	CZECHAL4	138	524	569	28.920	28.882	0.038	0.13%	5	FALSE
514895	SARA 4	138	524	569	19.890	19.875	0.015	0.08%	5	FALSE
514906	JNSKAMO4	138	524	569	20.636	20.621	0.015	0.07%	5	FALSE
514934	DRAPER 7	345	524	569	25.966	25.917	0.049	0.19%	5	FALSE
515009	MCELROY4	138	524	568	13.578	13.568	0.010	0.07%	5	FALSE
515224	MUSKOGE7	345	524	565	27.401	27.393	0.008	0.03%	5	FALSE
515235	PECANCK7	345	524	565	21.223	21.216	0.007	0.03%	5	FALSE
515375	WWRDEHV7	345	524	566	19.998	19.982	0.016	0.08%	5	FALSE
515400	DMANCRK4	138	524	566	8.108	8.102	0.006	0.07%	5	FALSE
515444	MCNOWND7	345	524	567	23.587	23.534	0.053	0.23%	5	FALSE
515448	CRSRDSW7	345	524	566	12.141	12.126	0.015	0.12%	5	FALSE
515465	LGARBER4	138	524	569	21.432	21.413	0.019	0.09%	5	FALSE
515466	MITCHSB4	138	524	569	21.719	21.687	0.032	0.15%	5	FALSE
515477	CHSHLMV7	345	524	566	14.148	14.115	0.033	0.23%	5	FALSE
515543	RENFROW7	345	524	566	13.078	13.061	0.017	0.13%	5	FALSE
515549	MNCWND37	345	524	567	14.610	14.591	0.019	0.13%	5	FALSE
515574	SPGVLLY4	138	524	568	10.730	10.725	0.005	0.05%	5	FALSE
515582	SLNGWND7	345	524	566	8.471	8.464	0.007	0.08%	5	FALSE
515585	MAMTHPW7	345	524	566	13.796	13.777	0.019	0.14%	5	FALSE
515600	KNGFSHR7	345	524	569	12.046	12.023	0.023	0.19%	5	FALSE
515605	CANADN7	345	524	566	13.147	13.119	0.028	0.21%	5	FALSE
515800	GRACMNT7	345	524	567	19.503	19.487	0.016	0.08%	5	FALSE
515877	REDDIRT7	345	524	566	18.681	18.595	0.086	0.46%	5	FALSE
532794	ROSEHIL7	345	536	1537	17.638	17.619	0.019	0.11%	5	FALSE
584900	GEN-2015-052	345	536	1537	11.865	11.840	0.025	0.21%	5	FALSE
588039	G16133G16146	345	520	546	32.035	31.999	0.036	0.11%	5	FALSE
761250	GEN-2017-233	345	524	1	22.885	22.835	0.050	0.22%	5	FALSE
762342	GEN-2017-178	345	524	1	8.112	8.095	0.017	0.21%	5	FALSE
900004	TRW2-TRW3	345	524	566	6.237	6.231	0.006	0.10%	5	FALSE

Appendix C

SPP Disturbance Performance Requirements

Southwest Power Pool Disturbance Performance Requirements

Revision 3.0

July 21, 2016

SPP 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.

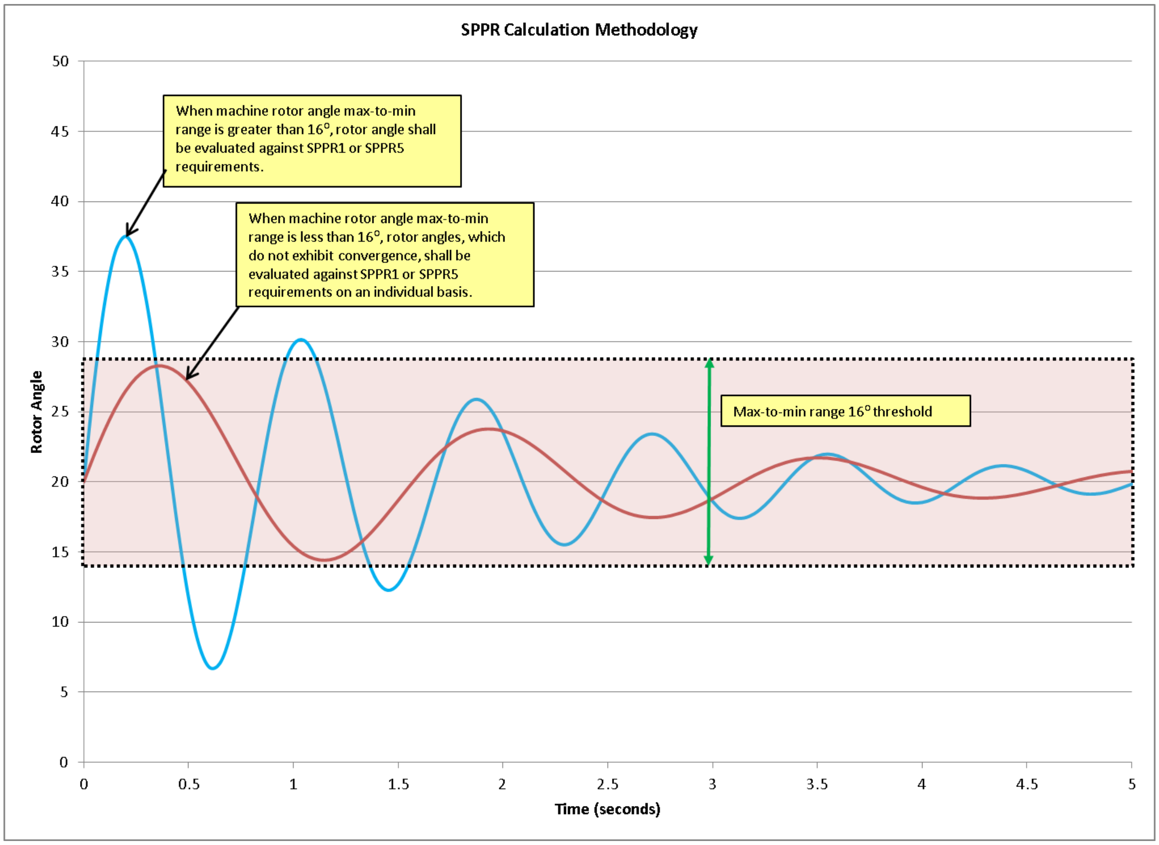


Figure 1. Applicability of 16 Degree Threshold

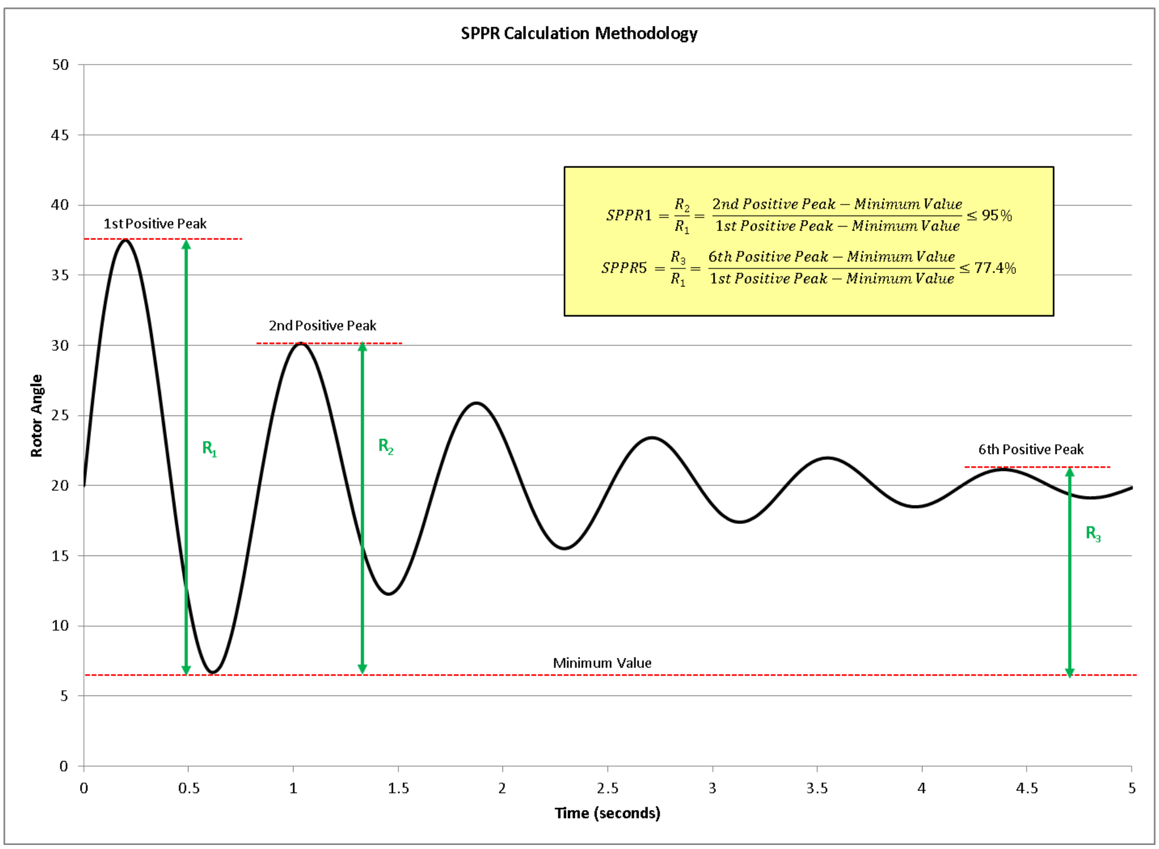


Figure 2. SPPR1 and SPPR5 Calculations

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.

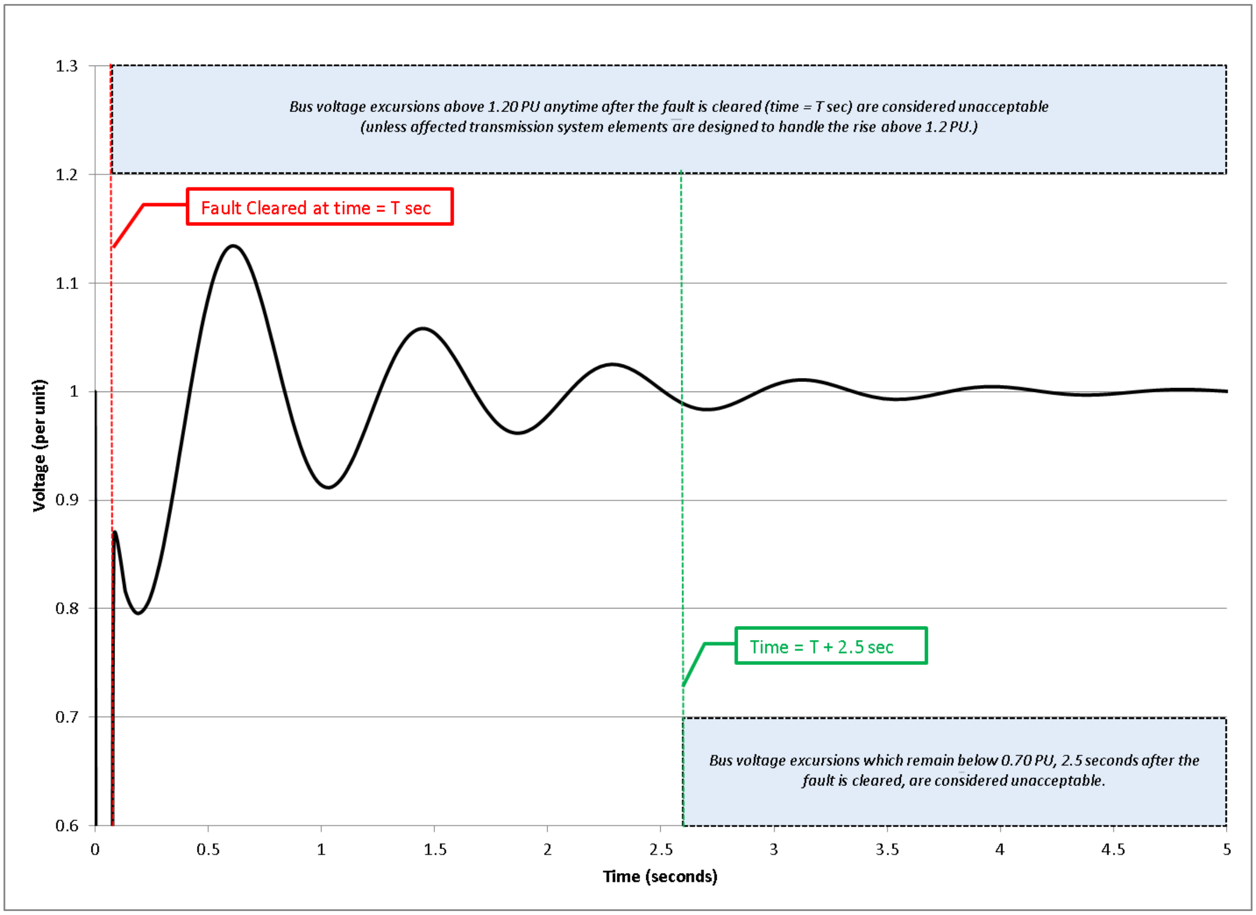


Figure 3. Transient Voltage Recovery Requirement

Appendix D

GEN-2016-119

Dynamic Stability Results with Existing Base Case Issues & Simulation Plots

Table D-1: **GEN-2016-119 Dynamic Stability Results w/ Existing DISIS Base Case Issues**

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT01-3PH	Pass	Pass	Stable (1, 2)	Pass	Pass	Stable (1, 2)
FLT04-3PH	Pass	Pass	Stable (1, 4)	Pass	Pass	Stable (1, 4)
FLT9001-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9002-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9003-3PH	Pass	Pass	Stable (1, 3, 4, 5, 6, 7)	Pass	Pass	Stable (1, 3, 4, 5, 6, 7)
FLT9004-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9005-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9006-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9007-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9008-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9009-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9010-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9011-3PH	Pass	Pass	Stable (1, 4)	Pass	Pass	Stable (1, 4)
FLT9012-3PH	Pass	Pass	Stable (1, 4)	Pass	Pass	Stable (1, 4)
FLT9013-3PH	Pass	Pass	Stable (1, 3, 5, 6, 7)	Pass	Pass	Stable (1, 3, 5, 6, 7)
FLT9014-3PH	Pass	Pass	Stable (1, 3)	Pass	Pass	Stable (1, 3)
FLT9015-3PH	Pass	Pass	Stable (1, 3, 5, 6, 7)	Pass	Pass	Stable (1, 3, 5, 6, 7)
FLT9016-3PH	Pass	Pass	Stable (1, 3, 5, 6, 7)	Pass	Pass	Stable (1, 3, 5, 6, 7)
FLT9017-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9018-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9019-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9020-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9021-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9022-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9023-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9024-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9025-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9026-3PH	Pass	Pass	Stable (1, 2)	Pass	Pass	Stable (1, 2)

Table D-1 Continued

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9027-3PH	Pass	Pass	Stable (1, 2)	Pass	Pass	Stable (1, 2)
FLT9013-PO1	Pass	Pass	Stable (1, 3, 5, 6, 7)	Pass	Pass	Stable (1, 3, 5, 6, 7)
FLT9014-PO1	Pass	Pass	Stable (1, 3)	Pass	Pass	Stable (1, 3)
FLT9015-PO1	Pass	Pass	Stable (1, 3, 5, 6, 7)	Pass	Pass	Stable (1, 3, 5, 6, 7)
FLT9016-PO1	Pass	Pass	Stable (1, 3, 5, 6, 7)	Pass	Pass	Stable (1, 3, 5, 6, 7)
FLT9004-PO2	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9005-PO2	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9006-PO2	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9007-PO2	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9008-PO2	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9009-PO2	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT9010-PO2	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT1001-SB	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT1002-SB	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT1003-SB	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT1004-SB	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT1005-SB	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)
FLT1006-SB	Pass	Pass	Stable (1)	Pass	Pass	Stable (1)

(1) Sustained oscillations were observed at units ROARK0 W1 and W2 (511968), BRKRDG_WTG 1 and 2 (514646), and G17-141 (760412) in both the pre and post modification models
(2) Unit G10-055 (560391) went out of sync in both the pre and post modification models
(3) Units MNCO (515967, 515968, 515969, 515984, 515985, 515986) did not reach stable active power within 20 seconds in both the pre and post modification models
(4) Unit G16-095 (587773) did not reach stable active power within 20 seconds in both the pre and post modification models
(5) Unit G16-097 (587793) did not reach stable active power within 20 seconds in both the pre and post modification models
(6) Units G17-027 (588713, 588714, 588715, 588716) did not reach stable active power within 20 seconds in both the pre and post modification models
(7) Units BLUCAN2 (599003, 920001, 920002, 920003, 920004) did not reach stable active power within 20 seconds in both the pre and post modification models

The results of the stability analysis showed that reactive power oscillations were observed for units ROARK0 W1 & W2 (511968) and BRKRDG_WTG 1 & 2 (514646) under multiple contingencies. For example, this issue was observed for fault FLT9001-3PH in the DISIS-2017-002 case without and with the GEN-2016-119 modification as shown in Figure D-1 and Figure D-2 respectively. Therefore, these oscillations were not attributed to the GEN-2016-119 modification request.

Figure D-1: FLT9001-3PH ROARK0 & BRKRDG_WTG Oscillations (25SP DISIS Case)

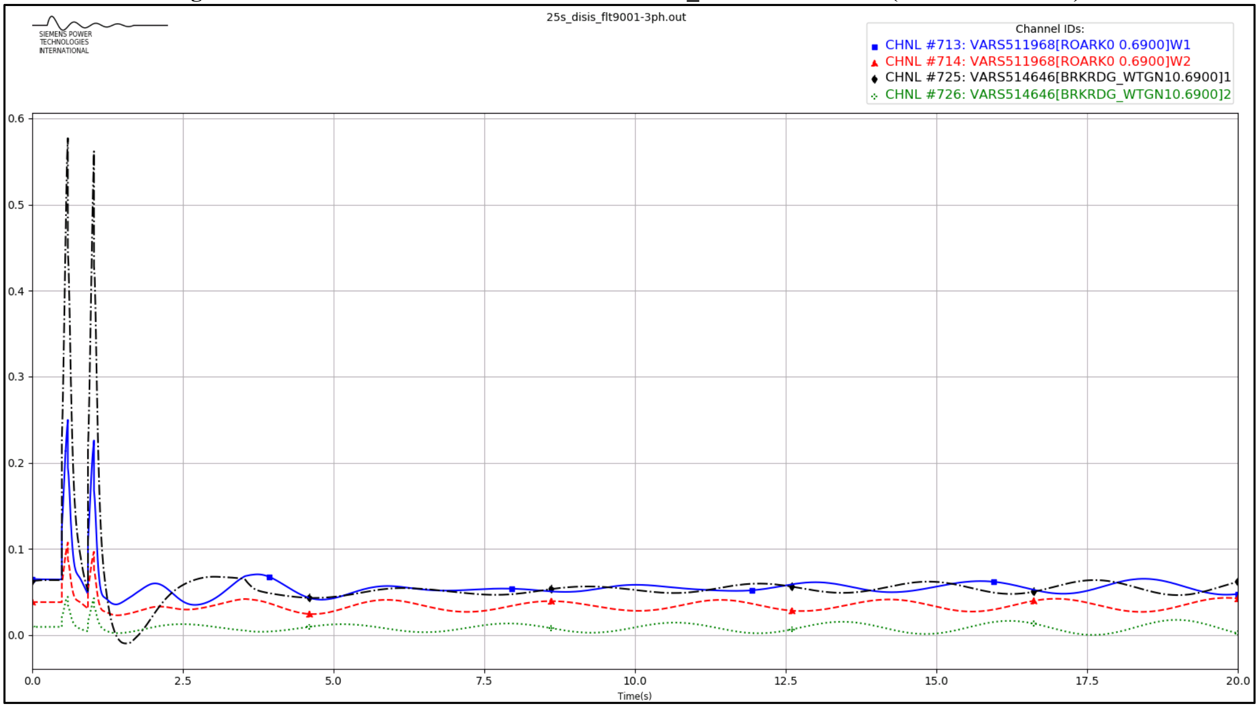
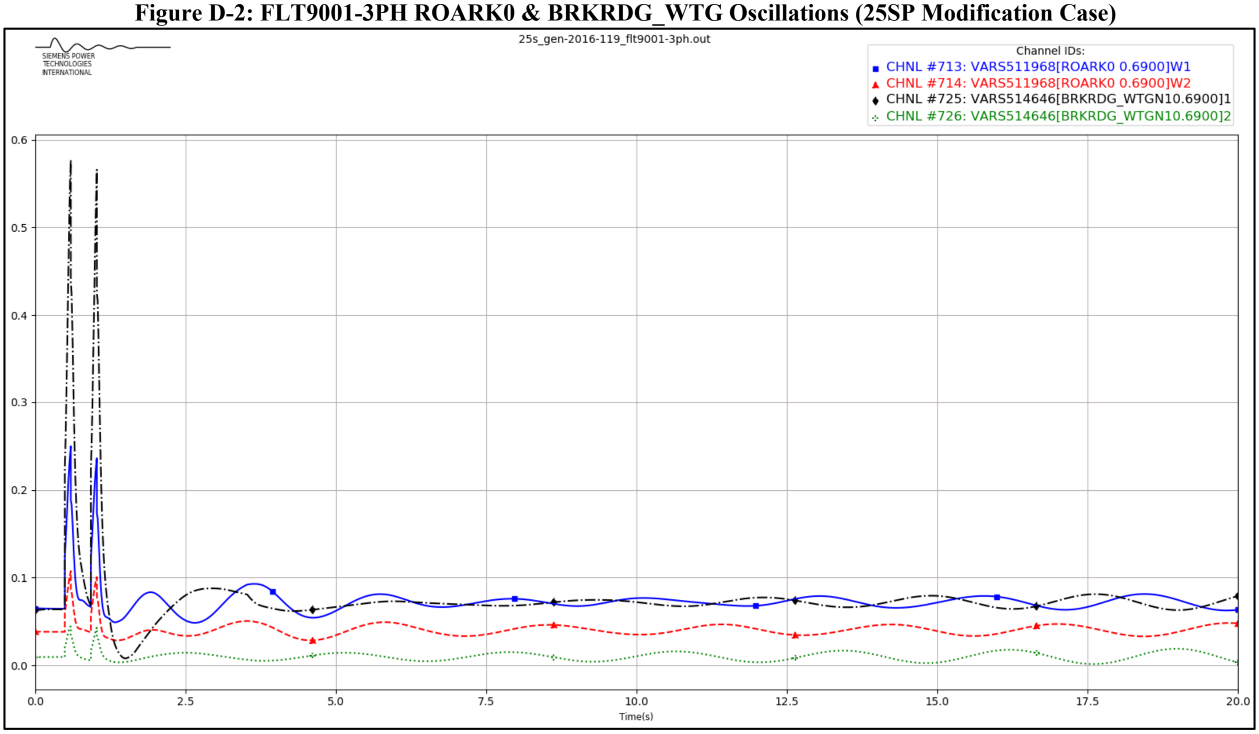


Figure D-2: FLT9001-3PH ROARK0 & BRKRDG_WTG Oscillations (25SP Modification Case)



Power oscillations were also observed for GEN-2017-141 (760412) under multiple contingencies. For example, this issue was observed for fault FLT9002-3PH in the DISIS-2017-002 case without and with the GEN-2016-119 modification as shown in Figure D-3 and Figure D-4, respectively. Therefore, these oscillations were not attributed to the GEN-2016-119 modification request.

Figure D-3: FLT9002-3PH GEN-2017-141 Oscillations (25SP DISIS Case)

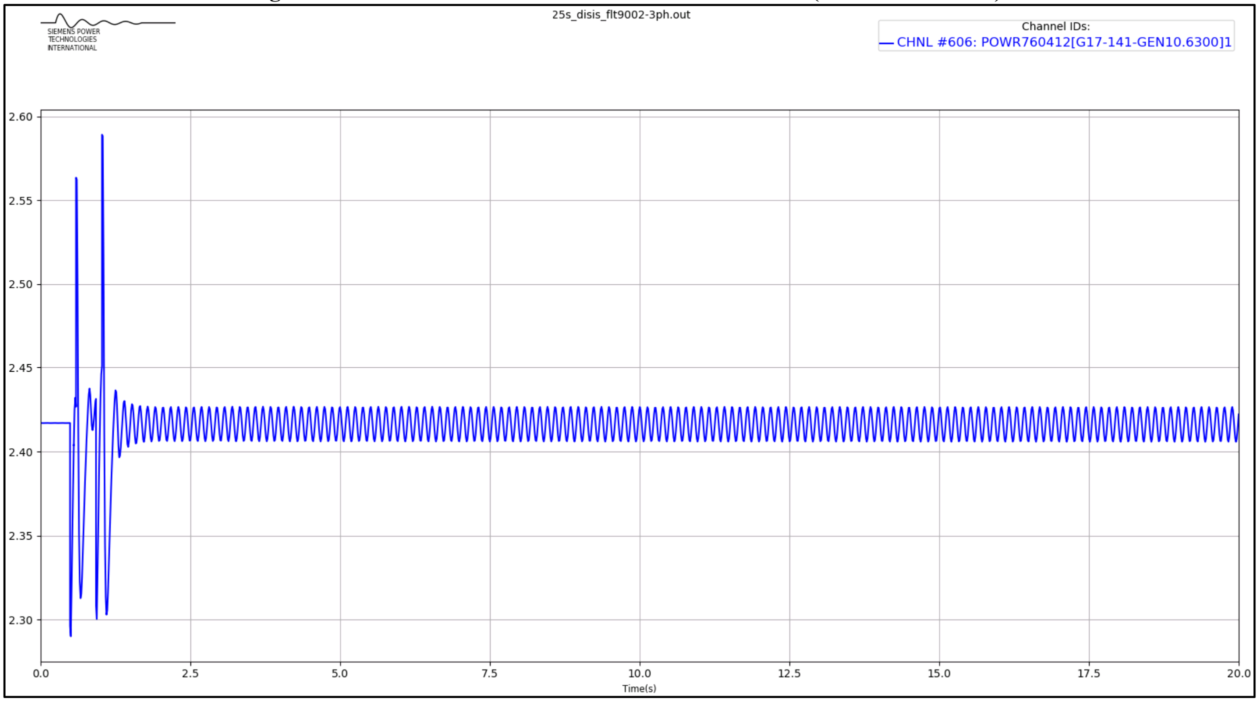
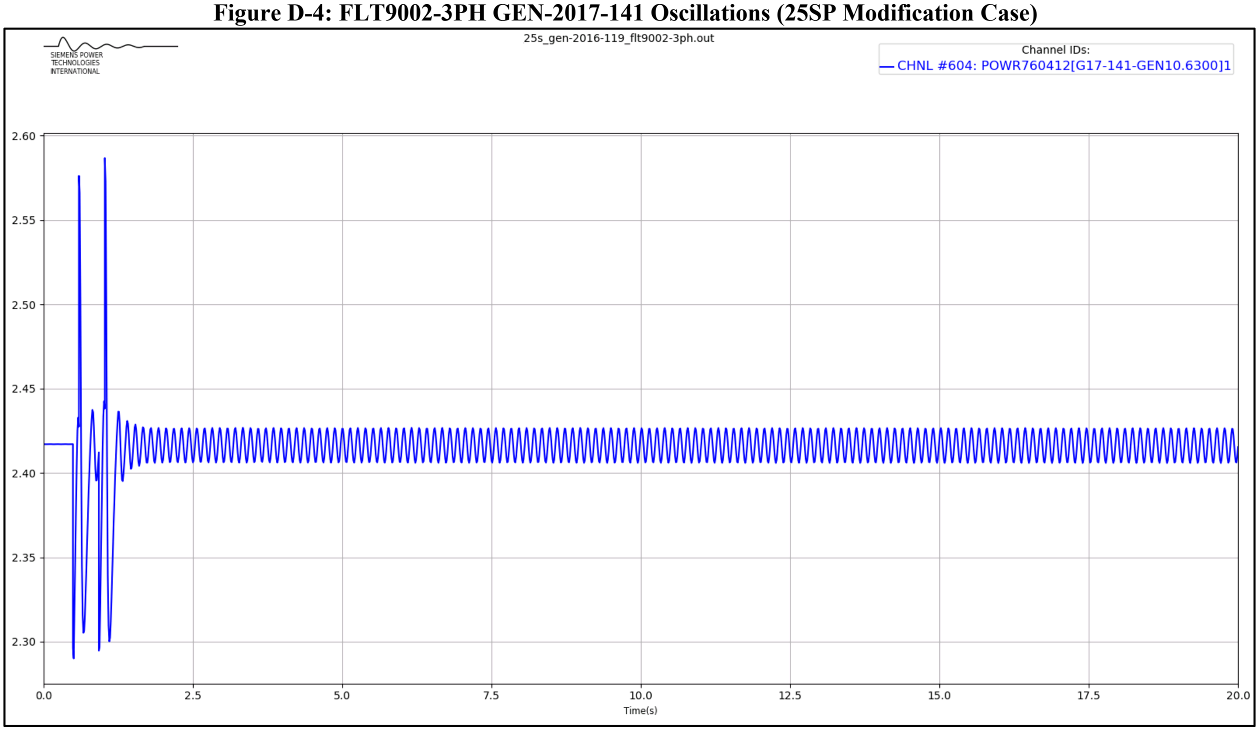


Figure D-4: FLT9002-3PH GEN-2017-141 Oscillations (25SP Modification Case)



In addition, GEN-2010-055 (560391) went out of sync under several contingencies. For example, this issue was observed for fault FLT01-3PH in the DISIS-2017-002 case without and with the GEN-2016-119 modification as shown in Figure D-5 and Figure D-6, respectively. Therefore, this issue was not attributed to the GEN-2016-119 modification request.

Figure D-5: FLT01-3PH GEN-2010-055 Out of Sync (25SP DISIS Case)

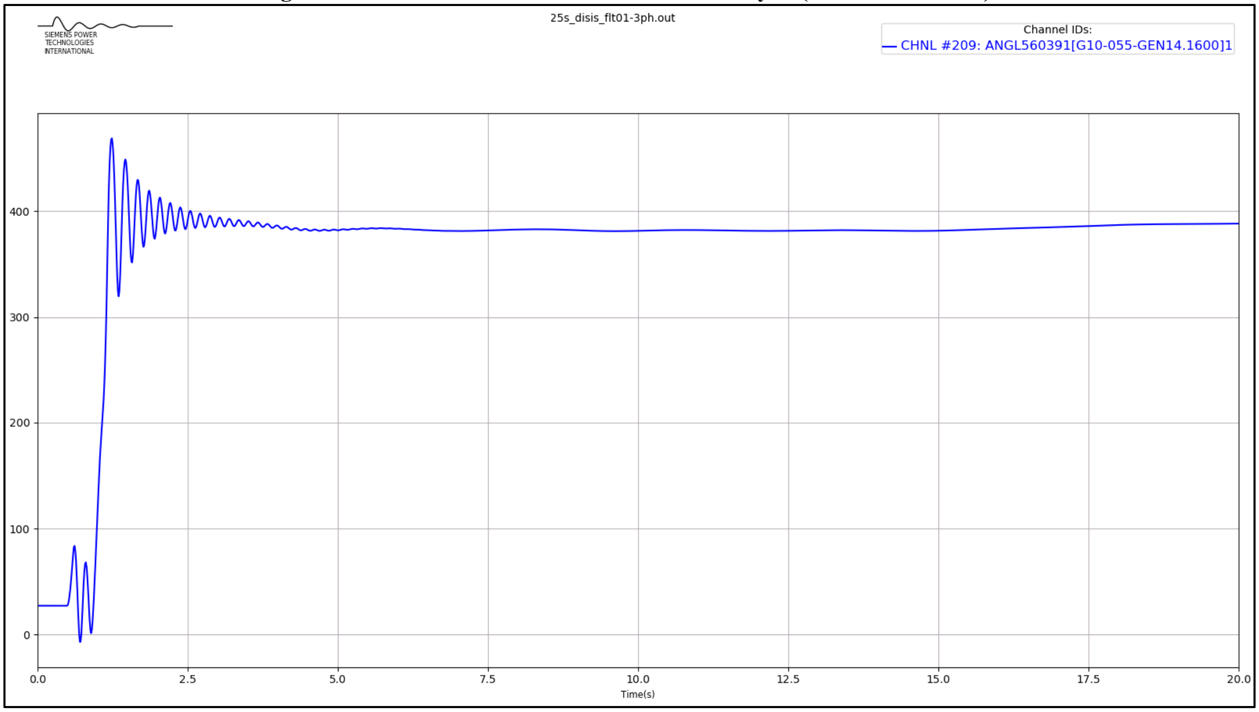
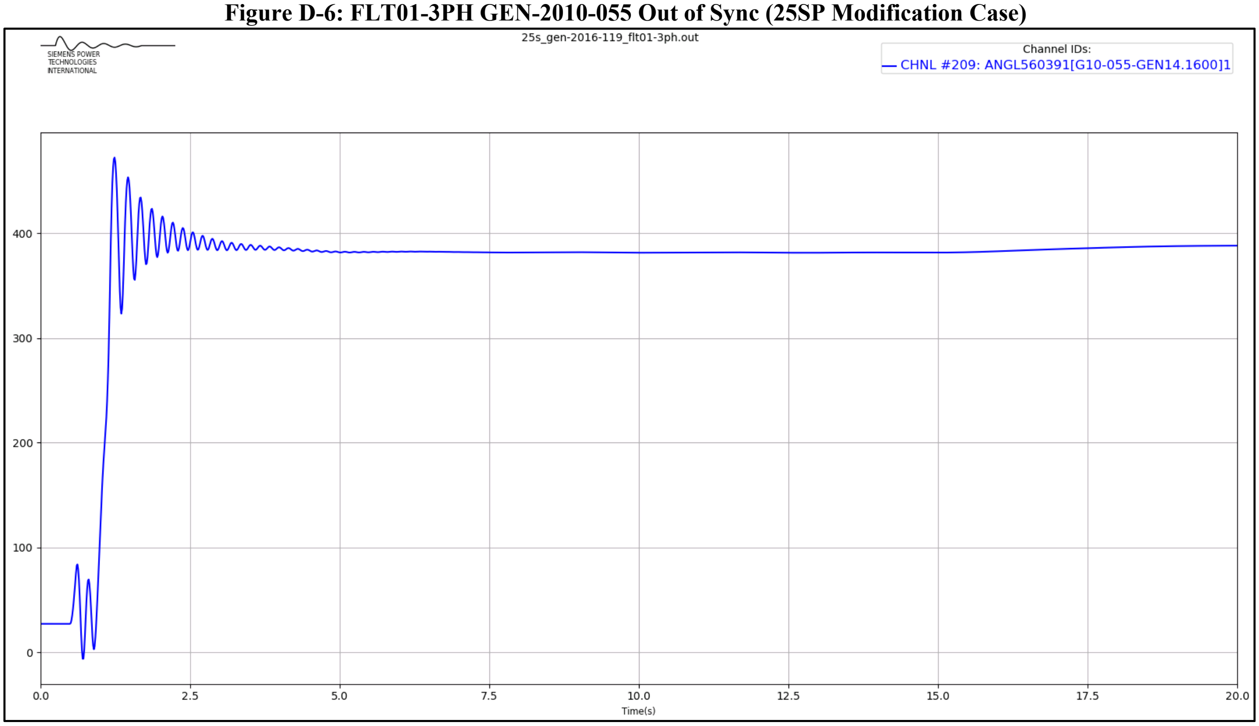


Figure D-6: FLT01-3PH GEN-2010-055 Out of Sync (25SP Modification Case)



Finally, MNCO units, GEN-2016-095[1], GEN-2016-097[1], GEN-2017-027, and BLUCAN2 units did not reach stable active power within 20 seconds under multiple contingencies. For example,

[1] GEN-2016-095 and GEN-2016-097 were recently modified and the response observed in this study may not be consistent with the latest project model performance.

this issue was observed under fault FLT9003-3PH in the DISIS-2017-002 case without and with the GEN-2016-119 modification as shown in Figure D-7 and Figure D-8, respectively. Therefore, the issue was not attributed to the GEN-2016-119 modification request.

Figure D-7: FLT9003-3PH Active Power (25SP DISIS Case)

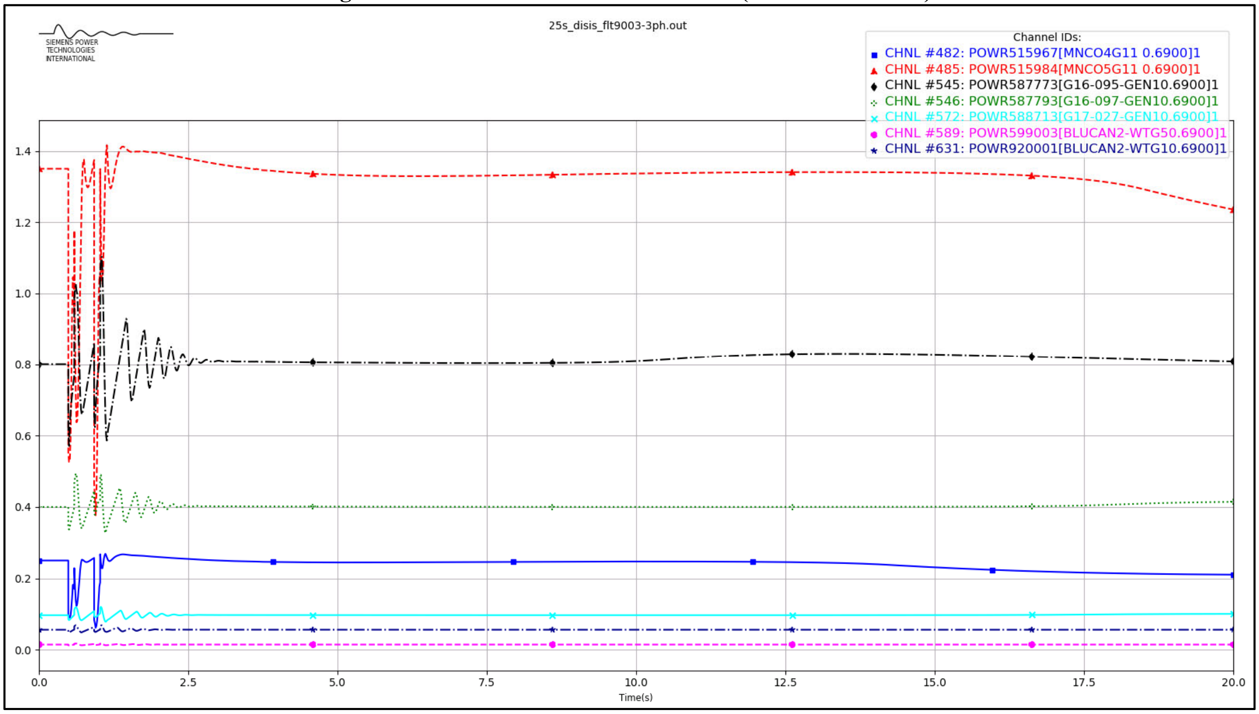
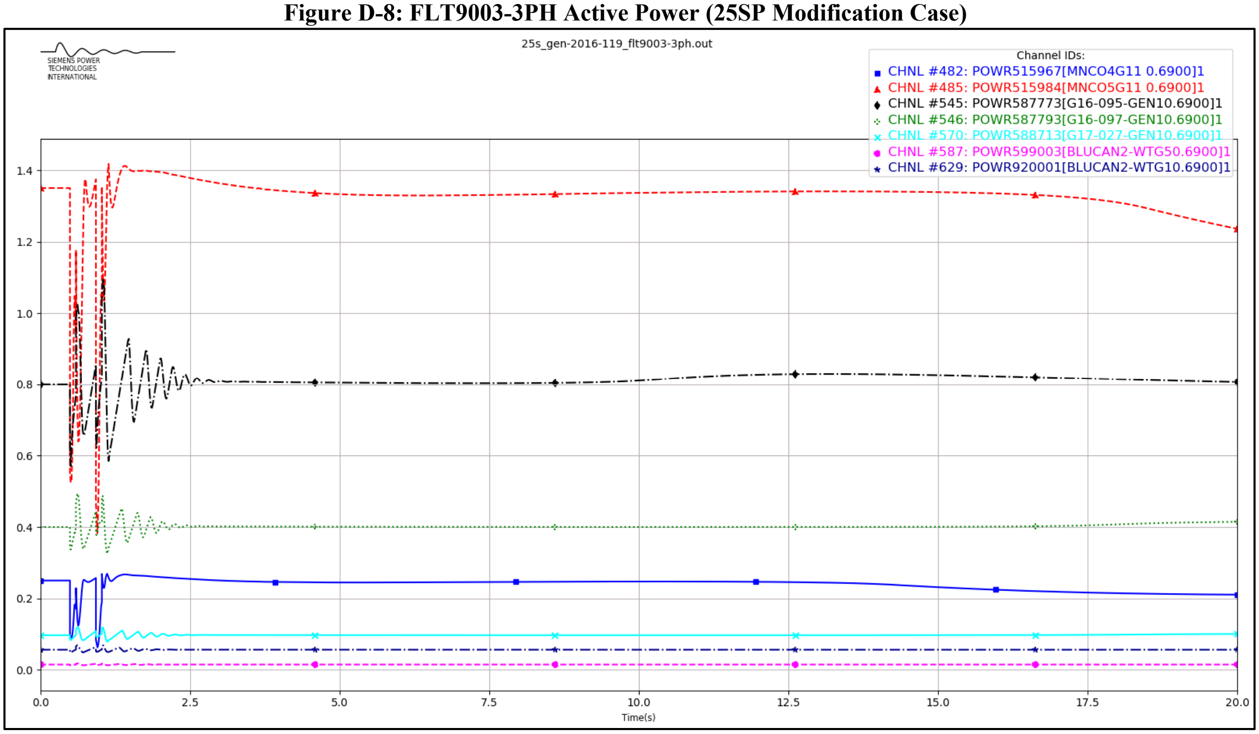


Figure D-8: FLT9003-3PH Active Power (25SP Modification Case)



2025 Summer Peak Plots

Including Prior Outage Plots

GEN-2016-119_25SP_Plots.pdf

2025 Winter Peak Plots

Including Prior Outage Plots

GEN-2016-119_25WP_Plots.pdf