Report on

GEN-2017-036 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-2017-036, an active Generation Interconnection Request (GIR) with a Point of Interconnection (POI) on the Snyder to Cache 138 kV line.

The GEN-2017-036 project interconnects in the American Electric Power (AEP) control area with a capacity of 100 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2017-036 to change the inverter configuration to 31 x SunGrow SG3600UD 3.268 MW for a total capacity of 101.308 MW. This generating capacity for GEN-2017-036 (101.308 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 100 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 requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI. In addition, the modification request included changes to the collection system, generator step-up transformer, generation interconnection line, and main substation transformer. The existing and modified configurations for GEN-2017-036 are shown in Table ES-2.

Table ES-1: GEN-2017-036 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2017-036	Tap on Snyder 138 kV (511435) to Cache 138 kV (511500) (TAP_G17-036 999600)	40 x TMEIC Solar Ware Samurai PHVL2700GR 2.5 MW	100

Table ES-2: GEN-2017-036 Modification Request

Facility	Existing Configuration	Modification Configuration
Point of Interconnection	Tap on Snyder 138 kV (511435) to Cache 138 kV (511500) (TAP_G17-036 999600)	Tap on Snyder 138 kV (511435) to Cache 138 kV (511500) (TAP_G17-036 999600)
Configuration/Capacity	40 x TMEIC Solar Ware Samurai PHVL2700GR 2.5 MW = 100 MW	31 x SunGrow SG3600UD 3.268 MW = 101.308 MW Units are rated at 3.6 MW, PPC in place to limit POI to 100 MW
Generation Interconnection Line	Length = 0.54 miles R = 0.000550 pu X = 0.002090 pu B = 0.000600 pu Rating MVA = 0 MVA	Length = 0.1 miles R = 0.000090 pu X = 0.000380 pu B = 0.000110 pu Rating MVA = 137 MVA
Main Substation Transformer[1]	X = 6.996%, R = 0.237%, Winding MVA = 70 MVA, Rating MVA = 117 MVA	X = 8.996%, R = 0.279%, Winding MVA = 80 MVA, Rating MVA = 133.3 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 40 X = 5.722%, R = 0.572%, Winding MVA = 108 MVA, Rating MVA = 108 MVA	Gen 1 Equivalent Qty: 31 X = 5.706%, R = 0.713%, Winding MVA = 111.6 MVA, Rating MVA = 111.6 MVA
Equivalent Collector Line[2]	R = 0.009160 pu X = 0.008980 pu B = 0.016298 pu	R = 0.004839 pu X = 0.005845 pu B = 0.014645 pu
Generator Dynamic Model[3] & Power Factor	40 X TMEIC Solar Ware Samurai PHVL2700GR 2.7 MVA (REGCAU1)[3] Leading: 0.926 Lagging: 0.926	31 x SunGrow SG3600UD 3.6 MVA (REGCA1)[3] Leading: 0.908 Lagging: 0.908
Reactive Power Devices	N/A	2 x 10 MVAR 34.5 Capacitor Bank

1) X and R based on Winding MVA, 2) All pu are on 100 MVA Base 3) DYR stability model name

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.75% compared to the DISIS-2017-002 power flow models (GEN-2017-036 dispatched to 100%). However, SPP determined that the change in inverter manufacturer from TMEIC to SunGrow 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-2017-036 project needed a 1.5 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 1.7 MVAr found in the DISIS-2017-001 study[2]. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during reduced generation 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-2017-036 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2017-036 POI was no greater than 0.41 kA. All three-phase fault current levels within 5 buses of the POI with the GEN-2017-036 generator online were below 26 kA.

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. 38 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 stability base case issues observed in the DISIS-2017-002 case both with and without the GEN-2017-036 modification. These were not attributed to the GEN-2017-036 modification request.

1. GEN-2016-095 and GEN-2016-097 did not reach a stable active power within 20 seconds under multiple contingencies[3].
2. Reactive power oscillations were observed for units ROARK0 W1 and W2 (511967 and 511968) under multiple contingencies.

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[1] Power System Simulator for Engineering
[2] DISIS-2017-001-2 Restudy of Stability and Short Circuit Analysis – June 16, 2022
[3] 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.

There were no damping or voltage recovery violations attributed to the GEN-2017-036 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-2017-036. 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 stability model parameters and, if needed, the equivalent collector system impedance between the existing configuration and the requested modification. Dynamic stability analysis and short circuit analysis would be required if the differences listed above were determined to have a significant impact on the most recently performed DISIS stability analysis.

1.3 Charging Current Compensation Analysis

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

1.4 Study Limitations

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

2.0 Project and Modification Request

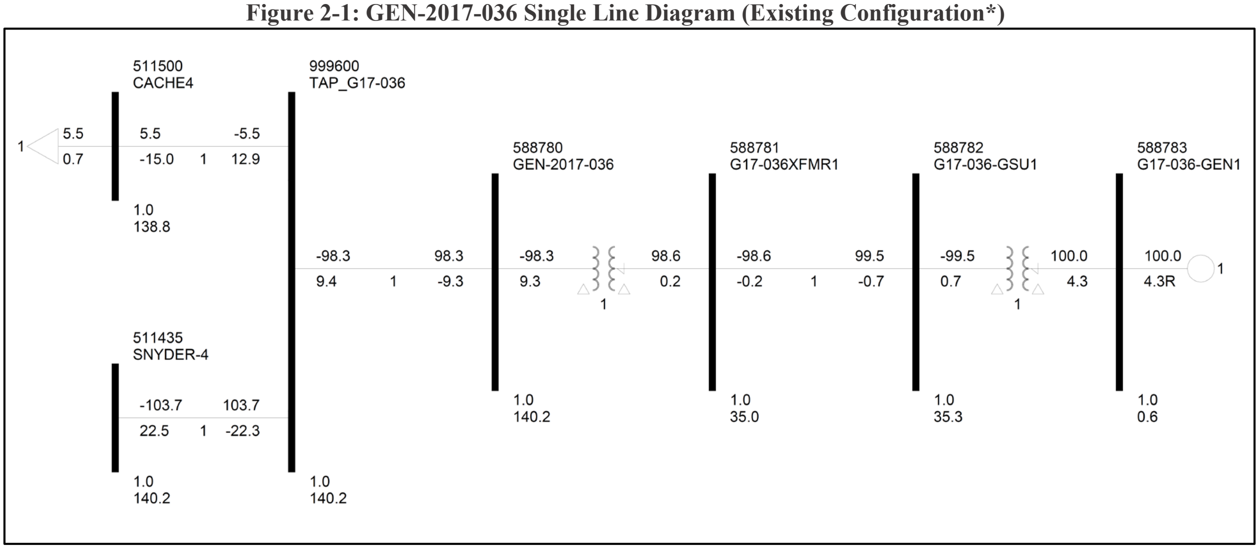
The GEN-2017-036 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a Point of Interconnection (POI) on the Snyder to Cache 138 kV line. At the time of report posting, GEN-2017-036 is an active Interconnection Request with a queue status of “IA FULLY EXECUTED/ON SCHEDULE.” GEN-2017-036 is a solar plant with a maximum summer and winter queue capacity of 100 MW with Energy Resource Interconnection Service (ERIS).

The GEN-2017-036 project is currently in the DISIS-2017-001 cluster. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2017-036 configuration using the DISIS-2017-002 stability models. The GEN-2017-036 project interconnects in the American Electric Power (AEP) control area with a capacity of 100 MW as shown in Table 2-1 below.

Table 2-1: GEN-2017-036 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2017-036	Tap on Snyder 138 kV (511435) to Cache 138 kV (511500) (TAP_G17-036 999600)	40 x TMEIC Solar Ware Samurai PHVL2700GR 2.5 MW	100

Figure 2-1: GEN-2017-036 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-2017-036 to an inverter configuration of 31 x SunGrow SG3600UD 3.268 MW for a total capacity of 101.308 MW. This generating capacity for GEN-2017-036 (101.308 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 100 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 transformer, generation interconnection line, and main substation transformer. Figure 2-2 shows the power flow model single line diagram for the GEN-2017-036 modification. The existing and modified configurations for GEN-2017-036 are shown in Table 2-2.

Figure 2-2: GEN-2017-036 Single Line Diagram (Modification Configuration)

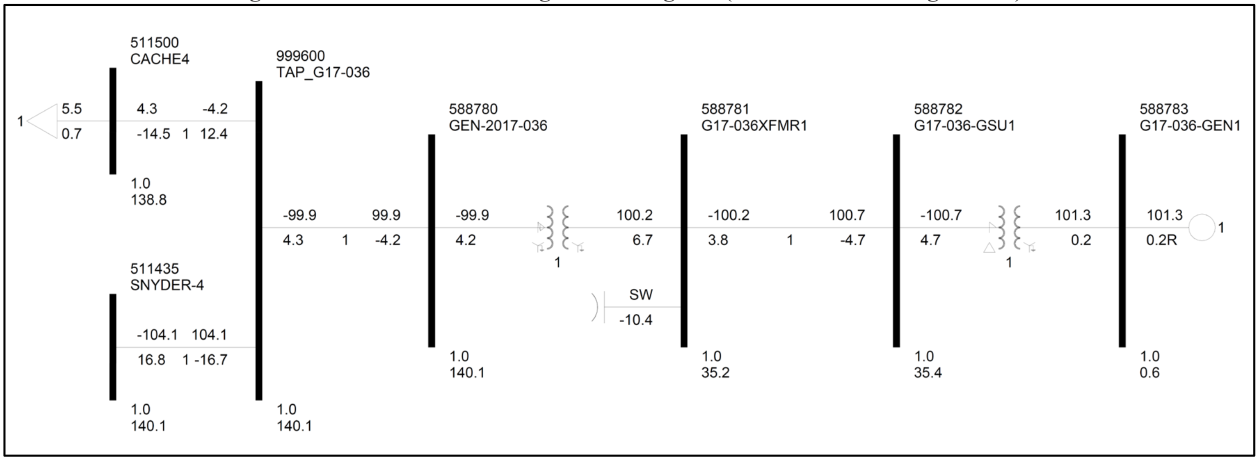


Table 2-2: GEN-2017-036 Modification Request

Facility	Existing Configuration	Modification Configuration
Point of Interconnection	Tap on Snyder 138 kV (511435) to Cache 138 kV (511500) (TAP_G17-036 999600)	Tap on Snyder 138 kV (511435) to Cache 138 kV (511500) (TAP_G17-036 999600)
Configuration/Capacity	40 x TMEIC Solar Ware Samurai PHVL2700GR 2.5 MW = 100 MW	31 x SunGrow SG3600UD 3.268 MW = 101.308 MW Units are rated at 3.6 MW, PPC in place to limit POI to 100 MW
Generation Interconnection Line	Length = 0.54 miles R = 0.000550 pu X = 0.002090 pu B = 0.000600 pu Rating MVA = 0 MVA	Length = 0.1 miles R = 0.000090 pu X = 0.000380 pu B = 0.000110 pu Rating MVA = 137 MVA
Main Substation Transformer[1]	X = 6.996%, R = 0.237%, Winding MVA = 70 MVA, Rating MVA = 117 MVA	X = 8.996%, R = 0.279%, Winding MVA = 80 MVA, Rating MVA = 133.3 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 40 X = 5.722%, R = 0.572%, Winding MVA = 108 MVA, Rating MVA = 108 MVA	Gen 1 Equivalent Qty: 31 X = 5.706%, R = 0.713%, Winding MVA = 111.6 MVA, Rating MVA = 111.6 MVA
Equivalent Collector Line[2]	R = 0.009160 pu X = 0.008980 pu B = 0.016298 pu	R = 0.004839 pu X = 0.005845 pu B = 0.014645 pu
Generator Dynamic Model[3] & Power Factor	40 X TMEIC Solar Ware Samurai PHVL2700GR 2.7 MVA (REGCAU1)[3] Leading: 0.926 Lagging: 0.926	31 x SunGrow SG3600UD 3.6 MVA (REGCA1)[3] Leading: 0.908 Lagging: 0.908
Reactive Power Devices	N/A	2 x 10 MVAR 34.5 Capacitor Bank

1) X and R based on Winding MVA, 2) All pu are on 100 MVA Base 3) 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 with the PPC in place for GEN-2017-036. 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 (increase of 0.75%) in the real power output at the POI between the studied DISIS-2017-002 power flow model configuration (GEN-2017-036 dispatched to 100%) and requested modification shown in Table 3-1.

Table 3-1: GEN-2017-036 POI Injection Comparison

Interconnection Request	Existing POI Injection (MW)	Modification POI Injection (MW)	POI Injection Difference %
GEN-2017-036	99.1	99.9	0.75%

3.2 Stability Model Parameters Comparison

SPP determined that short circuit and dynamic stability analyses were required because of the inverter change from TMEIC to SunGrow. 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 stability model parameters comparison was not needed for the determination of the scope of the study.

3.3 Equivalent Impedance Comparison Calculation

As the inverter 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-2017-036 to determine the capacitive charging effects during reduced generation conditions (unsuitable wind speeds, unsuitable solar irradiance, insufficient state of charge, idle conditions, curtailment, etc.) at the generation site and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

4.1 Methodology and Criteria

The GEN-2017-036 generators and capacitors were switched out of service while other system elements remained in-service. A shunt reactor was tested at the project's collection substation 34.5 kV bus to set the MVAr flow into the POI to approximately zero. The size of the shunt reactor is equivalent to the charging current value at unity voltage and the compensation provided is proportional to the voltage effects on the charging current (i.e., for voltages above unity, reactive compensation is greater than the size of the reactor).

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

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

4.2 Results

The results from the analysis showed that the GEN-2017-036 project needed approximately 1.5 MVAr of compensation at its project substation to reduce the POI MVAr to zero. This is a decrease from the 1.7 MVAr found in the DISIS-2017-001 study[4]. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the updated topology. The final shunt reactor requirements for GEN-2017-036 are shown in Table 4-1.

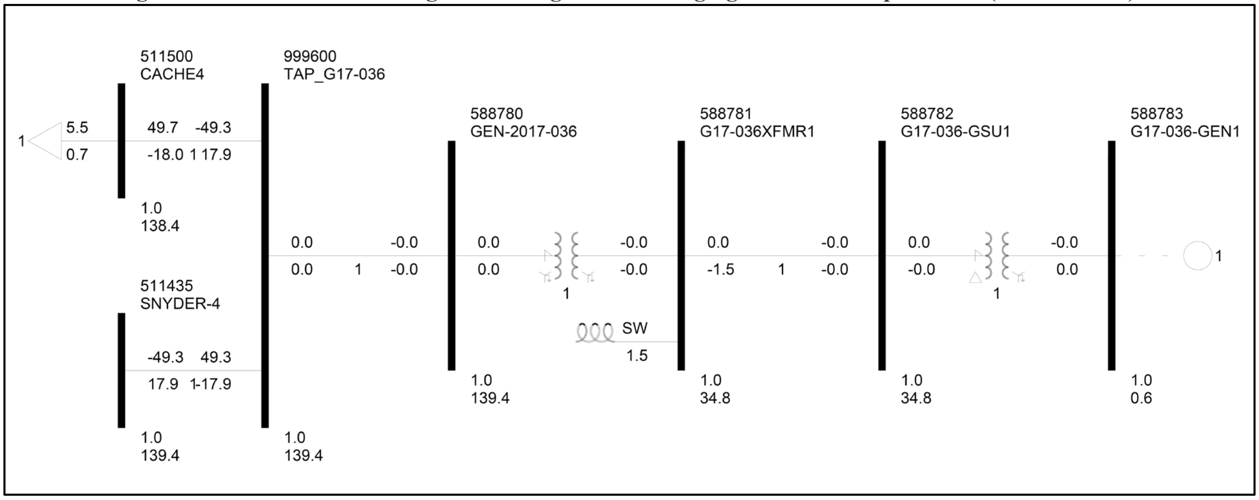
The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission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

Table 4-1: Shunt Reactor Size for Reduced Generation Study (Modification)

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)	
			25SP	25WP
GEN-2017-036	999600	TAP_G17-036 138 kV	1.5	1.5

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

Figure 4-1: GEN-2017-036 Single Line Diagram w/ Charging Current Compensation (Modification)



5.0 Short Circuit Analysis

A short circuit study was performed using the 25SP model for GEN-2017-036. 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 138 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels in the transmission system with and without GEN-2017-036 online.

Aneden created a short circuit model using the 2025 Summer Peak DISIS-2017-002 stability study model by adjusting the GEN-2017-036 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#
	588783
Machine MVA Base	111.6
R (pu)	0.0
X" (pu)	0.9426

*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-2017-036 POI bus (TAP_G17-036 138 kV - 999600) fault current magnitudes are provided in Table 5-2 showing a maximum fault current of 6.81 kA with the GEN-2017-036 project online. Table 5-3 shows the maximum fault current magnitudes and fault current increases with the GEN-2017-036 project online.

The maximum fault current calculated within 5 buses of the GEN-2017-036 POI (including the POI bus) was less than 26 kA for the 25SP model. The maximum GEN-2017-036 contribution to three-phase fault current was about 6.3% and 0.41 kA.

Table 5-2: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
25SP	6.41	6.81	0.41	6.3%

Table 5-3: 25SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	7.4	0.18	2.5%
138	25.2	0.41	6.3%
Max	**25.2**	**0.41**	**6.3%**

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the inverter configuration change and other modifications to GEN-2017-036. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix C. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix A. The simulation plots can be found in Appendix D.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested GEN-2017-036 configuration of 31 x SunGrow SG3600UD 3.268 MW (REGCA1). This stability analysis was performed using Siemens PTI's PSS/E version 34.8 software.

The modifications requested for the GEN-2017-036 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-2017-036 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 GEN-2017-036 (588783) frequency relay was disabled after observing the generator tripping during initial three phase fault simulations. This frequency tripping issue is a known PSS/E limitation when calculating bus frequency as it relates to non-conventional type devices.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2017-036 and other current and prior queued projects in their cluster group[5]. In addition, voltages of five (5) buses away from the POI of GEN-2017-036 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-2017-036 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.

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

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT03-3PH	P1	3 phase fault on the LG-YEAR4 (511428) to 112GORE4 (511488) 138kV line CKT 1, near LG-YEAR. a. Apply fault at the LG-YEAR 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT04-3PH	P1	3 phase fault on the L AIRGS4 (511429) to LAIRGST-4 (511510) 138kV line CKT 1, near L AIRGS4. a. Apply fault at the L AIRGS4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT09-3PH	P1	3 phase fault on the COMANC-4 (511437) to 112GORE4 (511488) 138kV line CKT 1, near COMANC-4. a. Apply fault at the COMANC-4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT22-3PH	P1	3 phase fault on the LWS-NTP4 (511471) to 112GORE4 (511488) 138kV line CKT 1, near LWS-NTP4. a. Apply fault at the LWS-NTP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT25-3PH	P1	3 phase fault on the 112GORE4 (511488) to LAIRGST4 (511510) 138kV line CKT 1, near 112GORE4. a. Apply fault at the 112GORE4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT26-3PH	P1	3 phase fault on the CACHE4 (511500) to TAP_G17-036 (999600) 138kV line CKT 1, near CACHE4. a. Apply fault at the CACHE4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9001-3PH	P1	3 phase fault on the TAP_G17-036 (999600) to CACHE4 (511500) 138kV line CKT 1, near TAP_G17-036. a. Apply fault at the TAP_G17-036 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on the TAP_G17-036 (999600) to SNYDER-4 (511435) 138kV line CKT 1, near TAP_G17-036. a. Apply fault at the TAP_G17-036 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1	3 phase fault on the CACHE4 (511500) to LAIRGST4 (511510) 138kV line CKT 1, near CACHE4. a. Apply fault at the CACHE4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9004-3PH	P1	3 phase fault on the LAIRGST4 (511510) to 112GORE4 (511488) 138kV line CKT 1, near LAIRGST4. a. Apply fault at the LAIRGST4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on the LAIRGST4 (511510) to L AIRGS4 (511429) 138kV line CKT 1, near LAIRGST4. a. Apply fault at the LAIRGST4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9006-3PH	P1	3 phase fault on the 112GORE4 (511488) to COMANC-4 (511437) 138kV line CKT 1, near 112GORE4. a. Apply fault at the 112GORE4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9007-3PH	P1	3 phase fault on the 112GORE4 (511488) to LWS-NTP4 (511471) 138kV line CKT 1, near 112GORE4. a. Apply fault at the 112GORE4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 phase fault on the 112GORE4 (511488) to LG-YEAR4 (511428) 138kV line CKT 1, near 112GORE4. a. Apply fault at the 112GORE4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	P1	3 phase fault on the 112GORE4 (511488) to RPPAPER4 (511512) 138kV line CKT 1, near 112GORE4. a. Apply fault at the 112GORE4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9010-3PH	P1	3 phase fault on the SNYDER-4 (511435) to SNYDER 4 (521052) 138kV line CKT 1, near SNYDER-4. a. Apply fault at the SNYDER-4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9011-3PH	P1	3 phase fault on the SNYDER-4 (511435) to ALTUSJT4 (511440) 138kV line CKT 1, near SNYDER-4. a. Apply fault at the SNYDER-4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9012-3PH	P1	3 phase fault on the SNYDER 138kV (511435) / 69 kV (511475)/ 13.8kV (511419) XFMR CKT 1, near SNYDER-4 (511435) 138kV. a. Apply fault at the SNYDER-4 138kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9013-3PH	P1	3 phase fault on the SNYDER 4 (521052) to CACHEJ4 (521190) 138kV line CKT 1, near SNYDER 4. a. Apply fault at the SNYDER 4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9014-3PH	P1	3 phase fault on the SNYDER 4 (521052) to GEN-2015-013 (562683) 138kV line CKT 1, near SNYDER 4. a. Apply fault at the SNYDER 4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. Trip generator G15-013-GEN1 (562685). c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9015-3PH	P1	3 phase fault on the SNYDER_1 138kV (521052) / 69 kV (521051)/ 13.8kV (521176) XFMR CKT 1, near SNYDER 4 (521052) 138kV. a. Apply fault at the SNYDER 4 138kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9016-3PH	P1	3 phase fault on the ALTUSJCT 138kV (511440) / 69 kV (511441)/ 13.8kV (511420) XFMR CKT 1, near ALTUSJT4 (511440) 138kV. a. Apply fault at the ALTUSJT4 138kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9017-3PH	P1	3 phase fault on the ALTUSJT4 (511440) to RUSSELL4 (521043) 138kV line CKT 1, near ALTUSJT4. a. Apply fault at the ALTUSJT4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9018-3PH	P1	3 phase fault on the ALTUSJT4 (511440) to OMPARK-4 (529345) 138kV line CKT 1, near ALTUSJT4. a. Apply fault at the ALTUSJT4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9019-3PH	P1	3 phase fault on the CACHEJ4 (521190) to MDCPRK4 (520404) 138kV line CKT 1, near CACHEJ4. a. Apply fault at the CACHEJ4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9020-3PH	P1	3 phase fault on the CACHEJ4 (521190) to CACHE4 (520410) 138kV line CKT 1, near CACHEJ4. a. Apply fault at the CACHEJ4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9006-PO1	P6	**PRIOR OUTAGE of TAP_G17-036 (999600) to SNYDER-4 (511435) 138kV line CKT 1;** 3 phase fault on the 112GORE4 (511488) to COMANC-4 (511437) 138kV line CKT 1, near 112GORE4. a. Apply fault at the 112GORE4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9007-PO1	P6	**PRIOR OUTAGE of TAP_G17-036 (999600) to SNYDER-4 (511435) 138kV line CKT 1;** 3 phase fault on the 112GORE4 (511488) to LWS-NTP4 (511471) 138kV line CKT 1, near 112GORE4. a. Apply fault at the 112GORE4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9008-PO1	P6	**PRIOR OUTAGE of TAP_G17-036 (999600) to SNYDER-4 (511435) 138kV line CKT 1;** 3 phase fault on the 112GORE4 (511488) to LG-YEAR4 (511428) 138kV line CKT 1, near 112GORE4. a. Apply fault at the 112GORE4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9009-PO1	P6	**PRIOR OUTAGE of TAP_G17-036 (999600) to SNYDER-4 (511435) 138kV line CKT 1;** 3 phase fault on the 112GORE4 (511488) to RPPAPER4 (511512) 138kV line CKT 1, near 112GORE4. a. Apply fault at the 112GORE4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9010-PO2	P6	**PRIOR OUTAGE of TAP_G17-036 (999600) to CACHE4 (511500) 138kV line CKT 1;** 3 phase fault on the SNYDER-4 (511435) to SNYDER 4 (521052) 138kV line CKT 1, near SNYDER-4. a. Apply fault at the SNYDER-4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9011-PO2	P6	**PRIOR OUTAGE of TAP_G17-036 (999600) to CACHE4 (511500) 138kV line CKT 1;** 3 phase fault on the SNYDER-4 (511435) to ALTUSJT4 (511440) 138kV line CKT 1, near SNYDER-4. a. Apply fault at the SNYDER-4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9012-PO2	P6	**PRIOR OUTAGE of TAP_G17-036 (999600) to CACHE4 (511500) 138kV line CKT 1;** 3 phase fault on the SNYDER 138kV (511435) / 69 kV (511475)/ 13.8kV (511419) XFMR CKT 1, near SNYDER-4 (511435) 138kV. a. Apply fault at the SNYDER-4 138kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT1001-SB	P4	**Stuck Breaker on SNYDER-4 (511435) 138kV bus.** a. Apply single-phase fault at SNYDER-4 (511435) on the 138kV bus. b. Wait 16 cycles and remove fault. c. Trip the SNYDER 138kV (511435) / 69 kV (511475)/ 13.8kV (511419) XFMR CKT 1. d. Trip the SNYDER-4 (511435) to ALTUSJT4 (511440) 138kV line CKT 1.
FLT1002-SB	P4	**Stuck Breaker on SNYDER-4 (511435) 138kV bus.** a. Apply single-phase fault at SNYDER-4 (511435) on the 138kV bus. b. Wait 16 cycles and remove fault. c. Trip the SNYDER 138kV (511435) / 69 kV (511475)/ 13.8kV (511419) XFMR CKT 1. d. Trip the SNYDER-4 (511435) to TAP_G17-036 (999600) 138kV line CKT 1.
FLT1003-SB	P4	**Stuck Breaker on SNYDER-4 (511435) 138kV bus.** a. Apply single-phase fault at SNYDER-4 (511435) on the 138kV bus. b. Wait 16 cycles and remove fault. c. Trip the SNYDER-4 (511435) to SNYDER 4 (521052) 138kV line CKT 1. d. Trip the SNYDER-4 (511435) to TAP_G17-036 (999600) 138kV line CKT 1.
FLT1004-SB	P4	**Stuck Breaker on SNYDER-4 (511435) 138kV bus.** a. Apply single-phase fault at SNYDER-4 (511435) on the 138kV bus. b. Wait 16 cycles and remove fault. c. Trip the SNYDER-4 (511435) to SNYDER 4 (521052) 138kV line CKT 1. d. Trip the SNYDER-4 (511435) to ALTUSJT4 (511440) 138kV line CKT 1.
FLT1005-SB	P4	**Stuck Breaker on 112GORE4 (511488) 138kV bus.** a. Apply single-phase fault at 112GORE4 (511488) on the 138kV bus. b. Wait 16 cycles and remove fault. c. Trip the BUS 112GORE4 (511488).

6.3 Results

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

Table 6-2: GEN-2017-036 Dynamic Stability Results

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT03-3PH	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (2)
FLT04-3PH	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (2)
FLT09-3PH	Pass	Pass	Stable (1, 2)	Pass	Pass	Stable (1, 2)
FLT22-3PH	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (1, 2, 3)
FLT25-3PH	Pass	Pass	Stable (1, 2, 3)	Pass	Pass	Stable (1, 2, 3)
FLT26-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 3)
FLT9001-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2)
FLT9002-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2)
FLT9003-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 3)

Table 6-2 continued

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9004-3PH	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (1, 2, 3)
FLT9005-3PH	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (1, 2, 3)
FLT9006-3PH	Pass	Pass	Stable (1, 2, 3)	Pass	Pass	Stable (1, 2, 3)
FLT9007-3PH	Pass	Pass	Stable (1, 2, 3)	Pass	Pass	Stable (1, 2, 3)
FLT9008-3PH	Pass	Pass	Stable (1, 2, 3)	Pass	Pass	Stable (1, 2, 3)
FLT9009-3PH	Pass	Pass	Stable (1, 2, 3)	Pass	Pass	Stable (1, 2, 3)
FLT9010-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2)
FLT9011-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2)
FLT9012-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2)
FLT9013-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2)
FLT9014-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2)
FLT9015-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2)
FLT9016-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2)
FLT9017-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2)
FLT9018-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2)
FLT9019-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2)
FLT9020-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2)
FLT9006-PO1	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (1, 2, 3)
FLT9007-PO1	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (1, 2, 3)
FLT9008-PO1	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (1, 2, 3)
FLT9009-PO1	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (1, 2, 3)
FLT9010-PO2	Pass	Pass	Stable (2)	Pass	Pass	Stable (2)
FLT9011-PO2	Pass	Pass	Stable (2)	Pass	Pass	Stable (2)
FLT9012-PO2	Pass	Pass	Stable (2)	Pass	Pass	Stable (2)
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

(1) G16-095 (587773) did not reach stable active power within 20 seconds in both the pre and post modification models[6]
(2) Sustained reacitve power oscillations were observed at units ROARK0 W1 and W2 (511968) in both the pre and post modification models
(3) G16-097 (587793) did not reach stable active power within 20 seconds in both the pre and post modification models[6]

GEN-2016-095 and GEN-2016-097 did not reach a stable active power within 20 seconds under multiple contingencies[6]. For example, this issue was observed for GEN-2016-095 and GEN-2016-097 under fault

[6] 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.

FLT25-3PH in the DISIS-2017-002 case without the GEN-2017-036 modification as shown in Figure 6-1 and with the GEN-2017-036 modification as shown in Figure 6-2. Therefore, the issue was not attributed to the GEN-2017-036 modification request.

Figure 6-1: FLT25-3PH GEN-2016-095 & GEN-2016-097 Active Power (25SP DISIS Case)

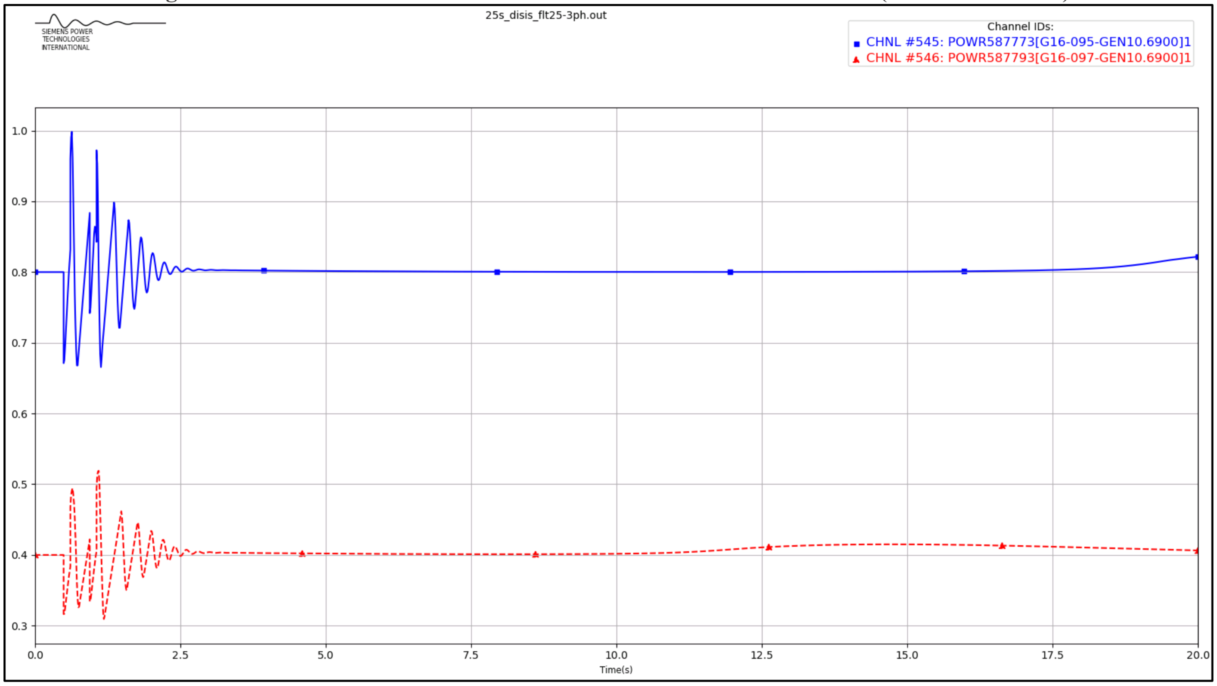
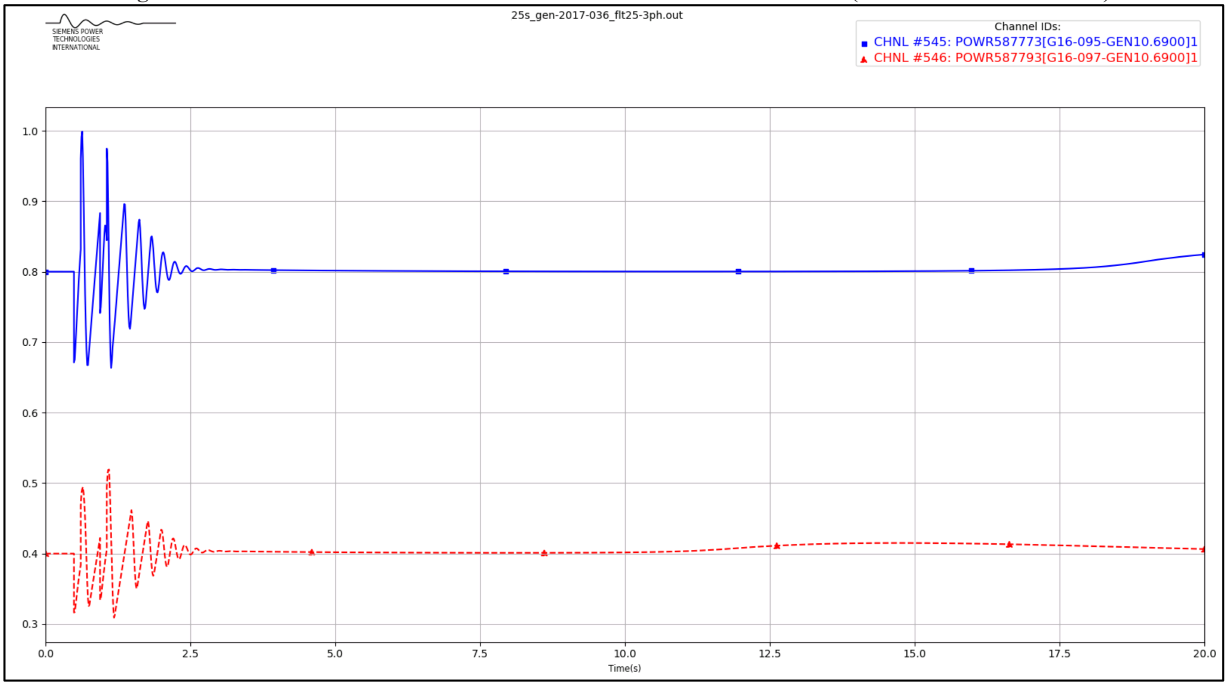


Figure 6-2: FLT25-3PH GEN-2016-095 & GEN-2016-097 Active Power (25SP Modification Case)



In addition, reactive power oscillations were observed for units ROARK0 W1 and W2 (511968) under multiple contingencies. For example, this issue was observed for fault FLT09-3PH in the DISIS-2017-002 case without the GEN-2017-036 modification as shown in Figure 6-3 below and with the GEN-2017-036 modification as shown in Figure 6-4. Therefore, these oscillations were not attributed to the GEN-2017-036 modification request.

Figure 6-3: FLT09-3PH ROARK0 Oscillations (25SP DISIS Case)

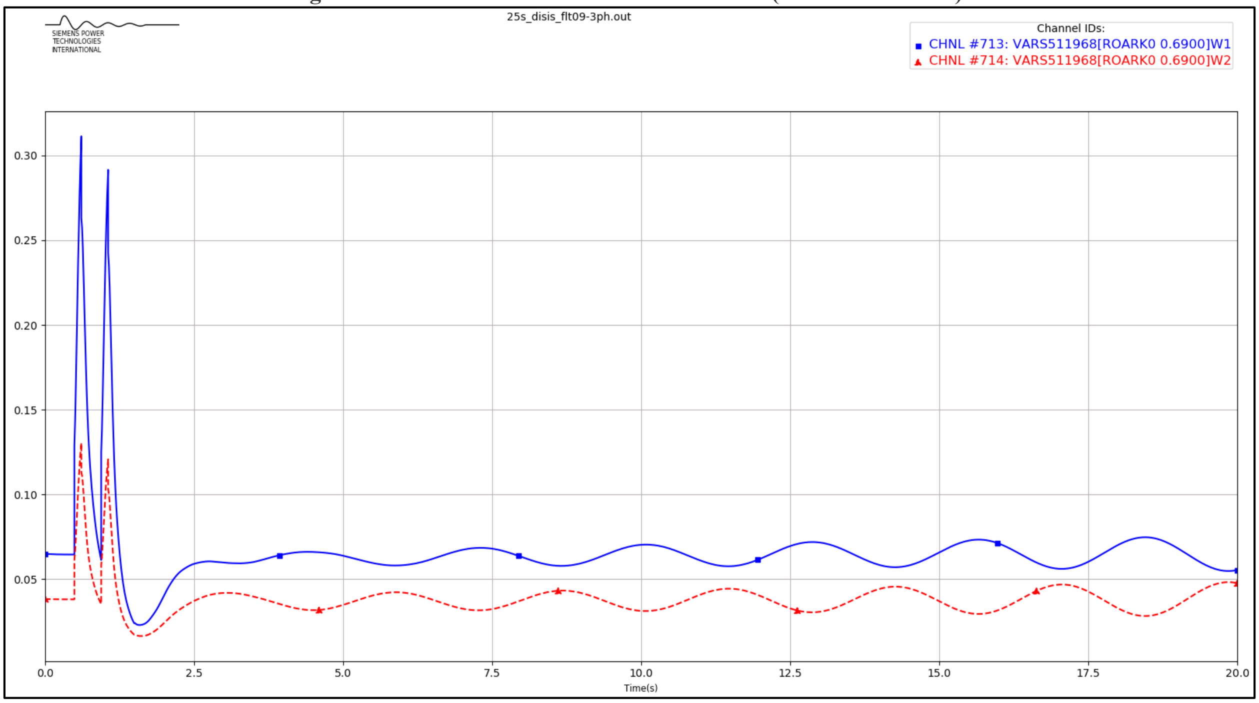
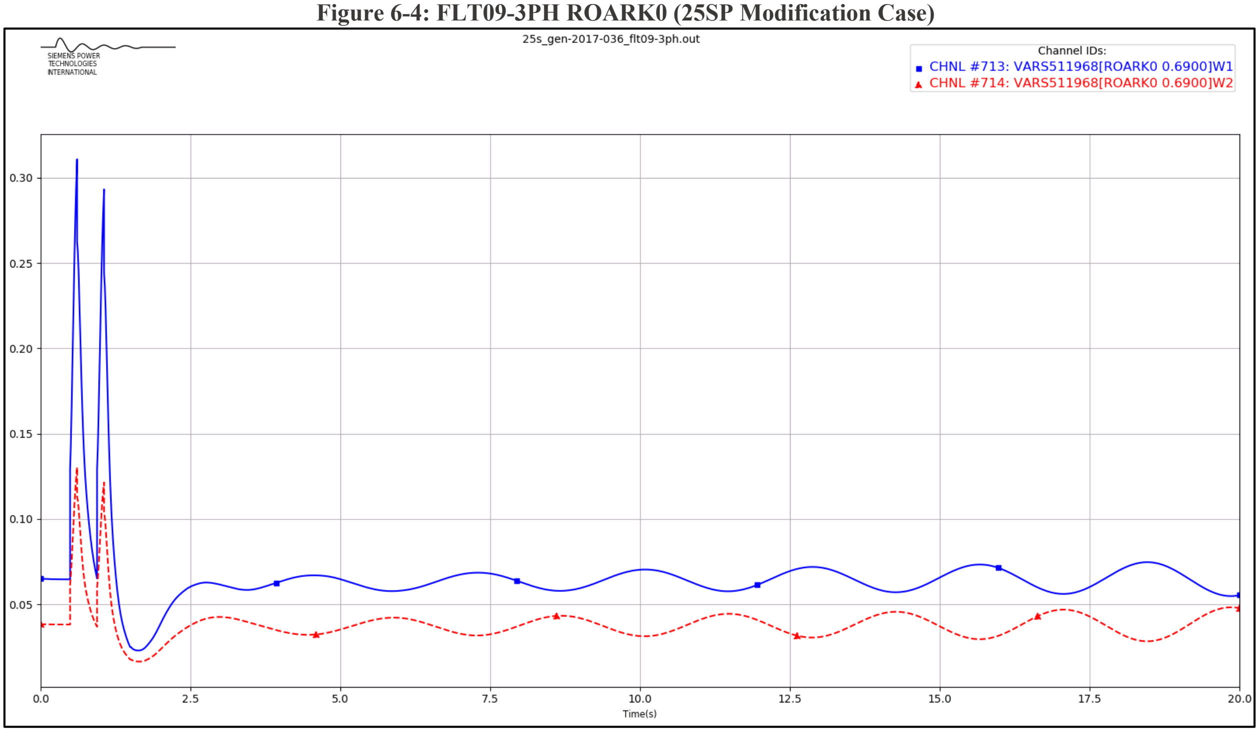


Figure 6-4: FLT09-3PH ROARK0 (25SP Modification Case)



There were no damping or voltage recovery violations attributed to the GEN-2017-036 modification request observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

7.0 Modified Capacity Exceeds GIA Capacity

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

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

7.1 Results

The modified generating capacity of GEN-2017-036 (101.308 MW) exceeds the GIA Interconnection Service amount, 100 MW, as listed in Appendix A of the GIA.

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

8.0 Material Modification Determination

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

8.1 Results

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

This determination implies that any network upgrades already required by GEN-2017-036 would not be negatively impacted and that no new upgrades are required due to the requested modification, thus not resulting in a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.

9.0 Conclusions

The Interconnection Customer for GEN-2017-036 requested a Modification Request Impact Study to assess the impact of the inverter and facility change to 31 x SunGrow SG3600UD 3.268 MW for a total capacity of 101.308 MW. This generating capacity for GEN-2017-036 (101.308 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 100 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 requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

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

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.75% compared to the DISIS-2017-002 power flow models (GEN-2017-036 dispatched to 100%). However, SPP determined that the change in inverter manufacturer from TMEIC to SunGrow 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-2017-036 project needed a 1.5 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 1.7 MVAr found in the DISIS-2017-001 study[7]. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during reduced generation 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-2017-036 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2017-036 POI was no greater than 0.41 kA. All three-phase fault current levels within 5 buses of the POI with the GEN-2017-036 generator online were below 26 kA.

The dynamic stability analysis was performed using PTI PSS/E version 34.8 software for the two modified study models: 2025 Summer Peak and 2025 Winter Peak. 38 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 stability base case issues observed in the DISIS-2017-002 case both with and without the GEN-2017-036 modification. These were not attributed to the GEN-2017-036 modification request.

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

1. GEN-2016-095 and GEN-2016-097 did not reach a stable active power within 20 seconds under multiple contingencies[8].
2. Reactive power oscillations were observed for units ROARK0 W1 and W2 (511967 and 511968) under multiple contingencies.

There were no damping or voltage recovery violations attributed to the GEN-2017-036 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.

[8] 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.

ANEDEN
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Appendices

GEN-2017-036
Modification Request Impact Study

Date of Submittal

January 19, 2023

anedenconsulting.com

Appendix A

GEN-2017-036 Generator Dynamic Model

```
//31 * 3.6MVA SunGrow SG3600UD
588783 'REGCA1' 1      0
        0.20000E-01   10.000     0.90000     0.50000      1.1000
         1.1000     0.90000     0.30000E-01  -1.0000     0.10000E-01
         0.0000      999.00     -999.00      1.0000     /
588783 'REECA1' 1
         0         0      1      0      0      0
        0.90000         1.1000        0.10000E-01    -0.10000        0.10000
         2.0000         1.0000        -1.0000         1.0000        0.10000E-01
         0.0000         0.0000        0.10000E-01     0.60000       -0.60000
         1.1000        0.90000        0.30000         5.0000        0.50000
         0.0000         0.0000        0.10000E-01      99.000        -99.000
         1.0000         0.0000         1.0000        0.10000E-01     0.50000E-01
         1.0000        0.49000         1.0000        0.50000         1.0000
         1.2000         1.0000        0.50000E-01     1.0000        0.49000
         1.0000        0.50000         1.0000         1.2000         1.0000     /
588783 'REPCA1' 1
         588780        588780        999600    '1 '       1      1      1
        0.50000E-01     0.50000         3.0000         0.0000        0.50000E-01
        0.70000         0.0000         0.0000         0.0000        0.50000E-01
       -0.50000E-01      0.0000         0.0000        0.60000       -0.60000
        0.50000        0.25000        0.25000       -0.60000E-03     0.60000E-03
         999.00        -999.00         1.0000         0.0000        0.50000
         20.000         20.000     /
58878301   'VTGTPAT'      588783 588783  '1 '     0.5000      999.00      3.0000      0.0000
/
58878302   'VTGTPAT'      588783 588783  '1 '     0.8800      999.00      1.1000      0.0000
/
58878303   'VTGTPAT'      588783 588783  '1 '     0.0000      1.1000      2.0000      0.0000
/
58878304   'VTGTPAT'      588783 588783  '1 '     0.0000      1.2000     0.16000      0.0000
/
58878305   'FRQTPAT'      588783 588783  '1 '     58.500      999.00      300.00      0.0000     /
58878306   'FRQTPAT'      588783 588783  '1 '     56.500      999.00     0.16000      0.0000
/
58878307   'FRQTPAT'      588783 588783  '1 '     0.0000      62.000     0.16000      0.0000
/
58878308   'FRQTPAT'      588783 588783  '1 '     0.0000      61.200      300.00      0.0000     /
```

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	%	999600	
999600	TAP_G17-036	138	525	590	6.814	6.409	0.405	6.32%	0	FALSE
511435	SNYDER-4	138	520	549	6.829	6.436	0.393	6.11%	1	FALSE
511500	CACHE4	138	520	549	8.364	8.222	0.142	1.73%	1	FALSE
588780	GEN-2017-036	138	525	590	6.776	N/A	N/A	N/A	1	FALSE
511440	ALTUSJT4	138	520	549	4.931	4.819	0.112	2.32%	2	FALSE
511475	SNYDER-2	69	520	549	7.367	7.187	0.180	2.50%	2	FALSE
511510	LAIRGST4	138	520	549	12.391	12.275	0.116	0.95%	2	FALSE
521052	SNYDER 4	138	525	594	6.239	5.950	0.289	4.86%	2	FALSE
511429	L AIRGS4	138	520	549	11.582	11.481	0.101	0.88%	3	FALSE
511441	ALTUSJT2	69	520	549	5.493	5.418	0.075	1.38%	3	FALSE
511462	HEADRIK2	69	520	549	4.428	4.370	0.058	1.33%	3	FALSE
511472	TIPTE T2	69	520	549	3.571	3.531	0.040	1.13%	3	FALSE
511488	112GORE4	138	520	549	12.799	12.684	0.115	0.91%	3	FALSE
511495	TOMSTEED2	69	520	549	4.085	4.047	0.038	0.94%	3	FALSE
521043	RUSSELL4	138	525	583	3.802	3.742	0.060	1.60%	3	FALSE
521051	SNYDER 2	69	525	594	6.760	6.612	0.148	2.24%	3	FALSE
521190	CACHEJ4	138	525	581	5.105	5.011	0.094	1.88%	3	FALSE
529345	OMPARK-4	138	527	1514	4.728	4.632	0.096	2.07%	3	FALSE
562683	GEN-2015-013	138	525	590	6.222	5.935	0.287	4.84%	3	FALSE
511428	LG-YEAR4	138	520	549	11.997	11.896	0.101	0.85%	4	FALSE
511437	COMANC-4	138	520	549	18.375	18.308	0.067	0.37%	4	FALSE
511444	ROSVTAP2	69	520	549	3.863	3.842	0.021	0.55%	4	FALSE
511460	FREDJC-2	69	520	549	2.731	2.708	0.023	0.85%	4	FALSE
511471	LWS-NTP4	138	520	549	11.748	11.675	0.073	0.63%	4	FALSE
511512	RPPAPER4	138	520	549	12.049	11.957	0.092	0.77%	4	FALSE
511543	TIPTN T2	69	520	549	4.426	4.368	0.058	1.33%	4	FALSE
511545	TIPTON 2	69	520	549	2.445	2.426	0.019	0.78%	4	FALSE
512110	LAKEP4WT	138	520	533	2.146	2.132	0.014	0.66%	4	FALSE
520404	MDCPRK4	138	525	581	5.535	5.490	0.045	0.82%	4	FALSE
520410	CACHE4	138	525	581	4.709	4.629	0.080	1.73%	4	FALSE
520528	ROSEVLT2	69	525	594	3.752	3.719	0.033	0.89%	4	FALSE
520541	SNYDRSB2	69	525	594	6.760	6.612	0.148	2.24%	4	FALSE
521042	RUSSELL2	69	525	583	5.219	5.168	0.051	0.99%	4	FALSE
521070	TIPTONJ2	69	525	594	3.879	3.836	0.043	1.12%	4	FALSE
529298	OMPVET-4	138	527	1514	4.530	4.449	0.081	1.82%	4	FALSE
511430	LWS N4	138	520	549	10.469	10.411	0.058	0.56%	5	FALSE
511432	R-AMOCO2	69	520	549	3.653	3.634	0.019	0.52%	5	FALSE
511438	DUKE---2	69	520	549	4.030	4.000	0.030	0.75%	5	FALSE
511439	LWSTAP 4	138	520	549	11.622	11.547	0.075	0.65%	5	FALSE
511465	HOBART-2	69	520	549	5.428	5.406	0.022	0.41%	5	FALSE
511467	L.E.S.-4	138	520	549	25.163	25.050	0.113	0.45%	5	FALSE
511479	TIPTCTY2	69	520	549	2.292	2.276	0.016	0.70%	5	FALSE
511494	COMMTAP4	138	520	549	21.926	21.840	0.086	0.39%	5	FALSE
511509	53CACHE4	138	520	549	11.783	11.714	0.069	0.59%	5	FALSE
511520	DAV TAP2	69	520	549	2.182	2.170	0.012	0.55%	5	FALSE
512101	CHILD4WT	138	520	533	1.665	1.659	0.006	0.36%	5	FALSE
512111	LAKEP2WT	69	520	533	3.055	3.040	0.015	0.49%	5	FALSE
520534	DUKE 2	69	525	583	5.219	5.168	0.051	0.99%	5	FALSE
520803	ALTUS_ 2	69	525	594	3.544	3.513	0.031	0.88%	5	FALSE
520914	FREDRIK2	69	525	594	3.400	3.372	0.028	0.83%	5	FALSE
520954	INDHOMA4	138	525	581	4.080	4.022	0.058	1.44%	5	FALSE
521009	NAVJOTP2	69	525	594	3.579	3.545	0.034	0.96%	5	FALSE
521024	PARADSE4	138	525	581	5.915	5.875	0.040	0.68%	5	FALSE
521069	TIPTON-2	69	525	594	2.053	2.041	0.012	0.59%	5	FALSE
521081	VERNON 2	69	525	594	2.389	2.375	0.014	0.59%	5	FALSE
529302	OMALTUS4	138	527	1514	4.424	4.353	0.071	1.63%	5	FALSE
529342	OMMANGM2	69	527	1515	3.141	3.133	0.008	0.26%	5	FALSE

Appendix C

SPP Disturbance Performance Requirements

Southwest Power Pool Disturbance Performance Requirements

Revision 3.0

July 21, 2016

Southwest Power Pool

Revision History

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

Southwest Power Pool
Disturbance Performance Requirements

OVERVIEW

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

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

ROTOR ANGLE DAMPING REQUIREMENT

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

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

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

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

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

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

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

   Damping Ratio $\geq$ 0.0081633

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

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

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

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

   Damping Ratio $\geq$ 0.0081633

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

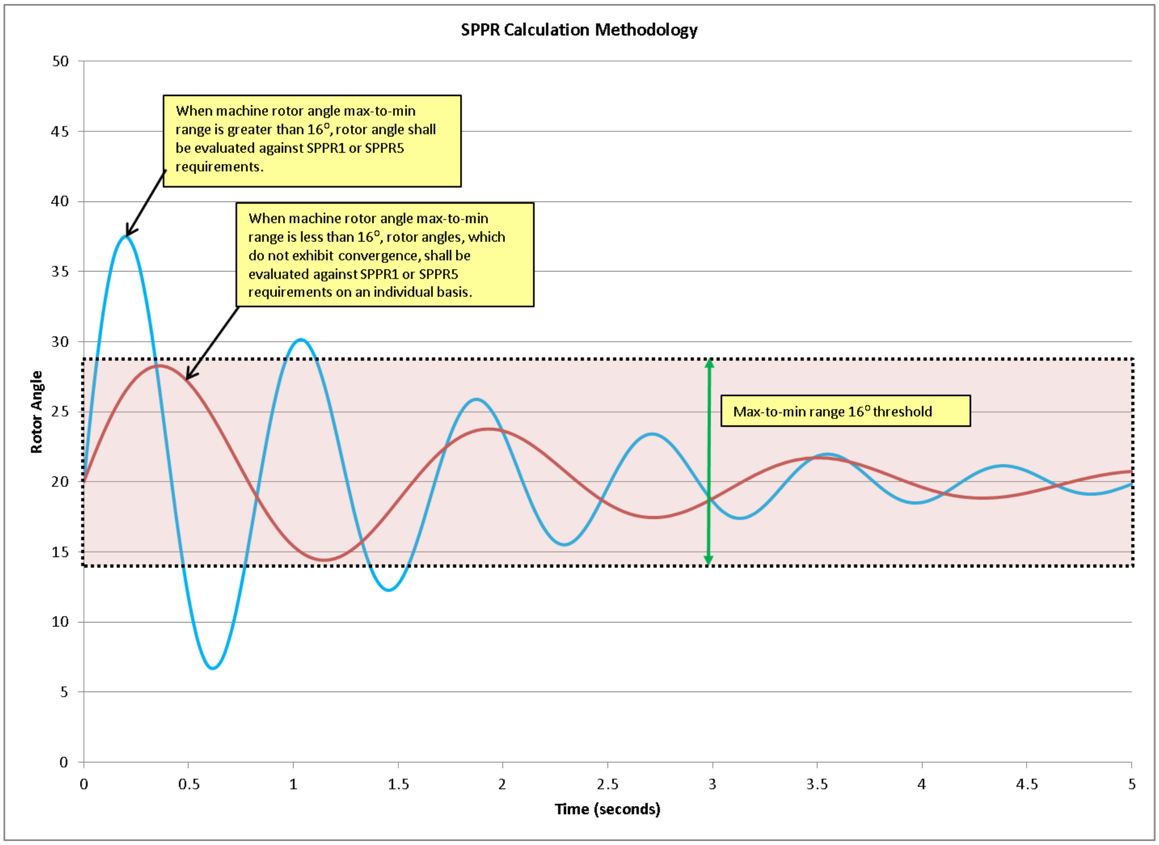

Figure 1. Applicability of 16 Degree Threshold

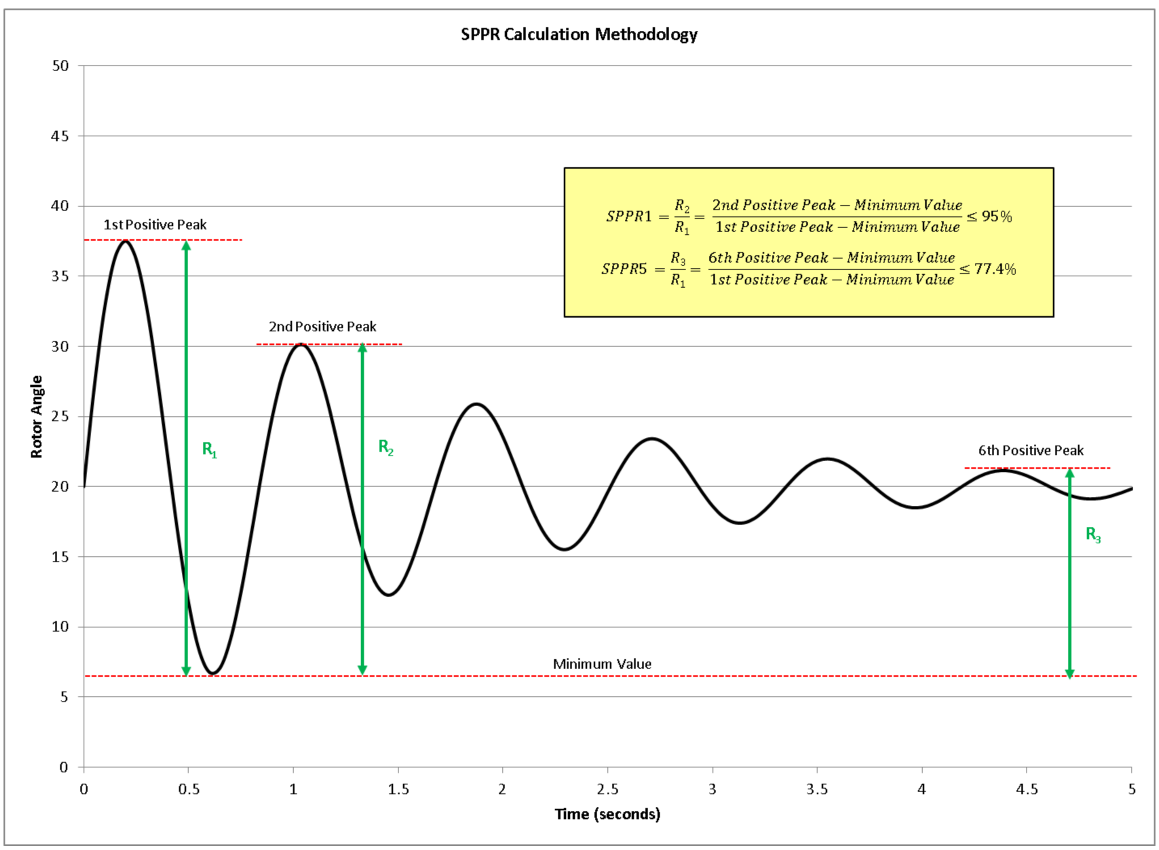

Figure 2. SPPR1 and SPPR5 Calculations

TRANSIENT VOLTAGE RECOVERY REQUIREMENT

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

Qualitatively, this Requirement is shown in Figure 3 below.

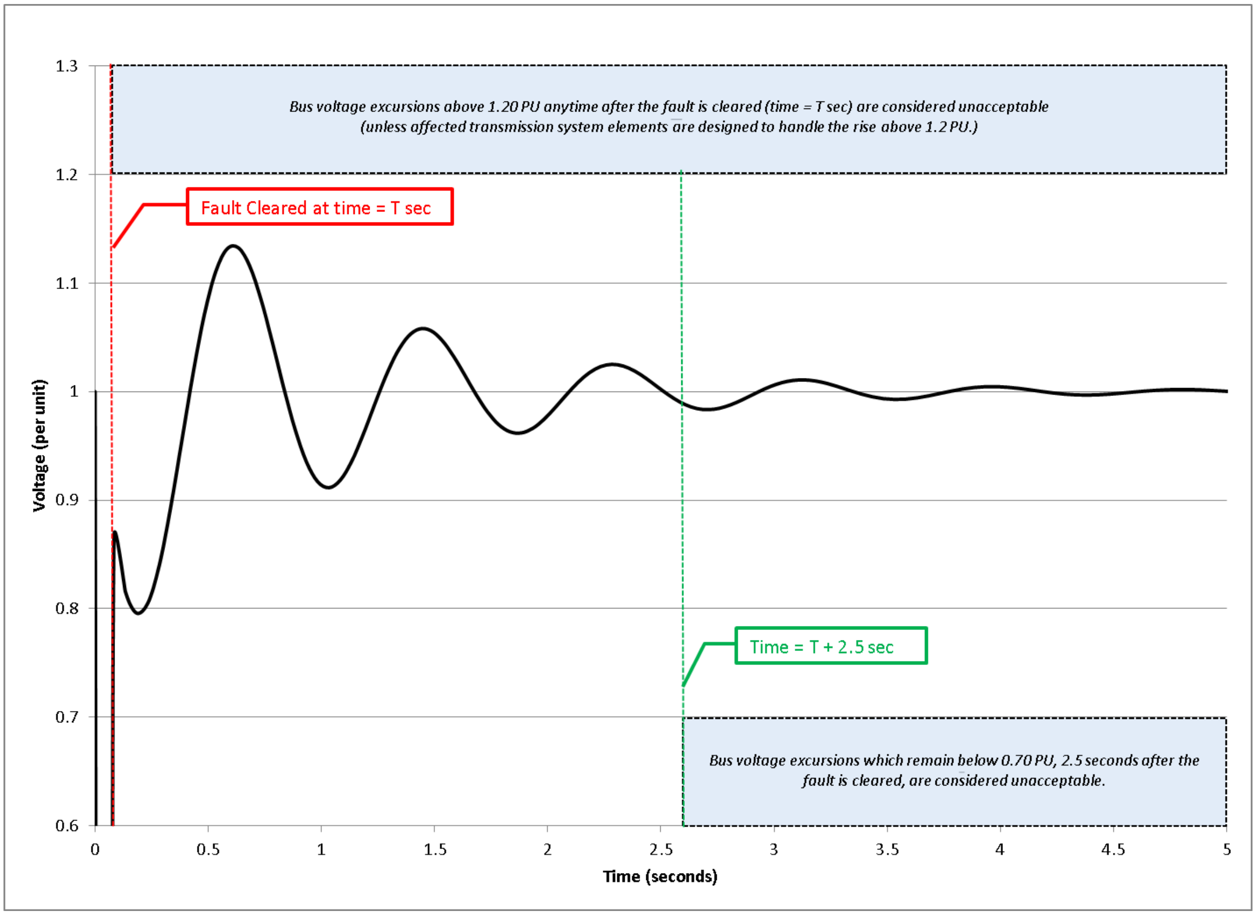

Figure 3. Transient Voltage Recovery Requirement

Appendix D

GEN-2017-036

Dynamic Stability Simulation Plots

2025 Summer Peak Plots

Including Prior Outage Plots

GEN-2017-036_25SP_Plots.pdf

2025 Winter Peak Plots

Including Prior Outage Plots

GEN-2017-036_25WP_Plots.pdf