Report on

GEN-2017-094 Modification Request Impact Study

Revision R1 January 6, 2023

Submitted to
Southwest Power Pool

anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
1/06/2023	Aneden Consulting	Initial Report Issued

Executive Summary

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

1.0 Scope of Study

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

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

1.1 Power Flow Analysis

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

1.2 Stability Analysis, Short Circuit Analysis

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

1.3 Charging Current Compensation Analysis

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

1.4 Study Limitations

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

2.0 Project and Modification Request

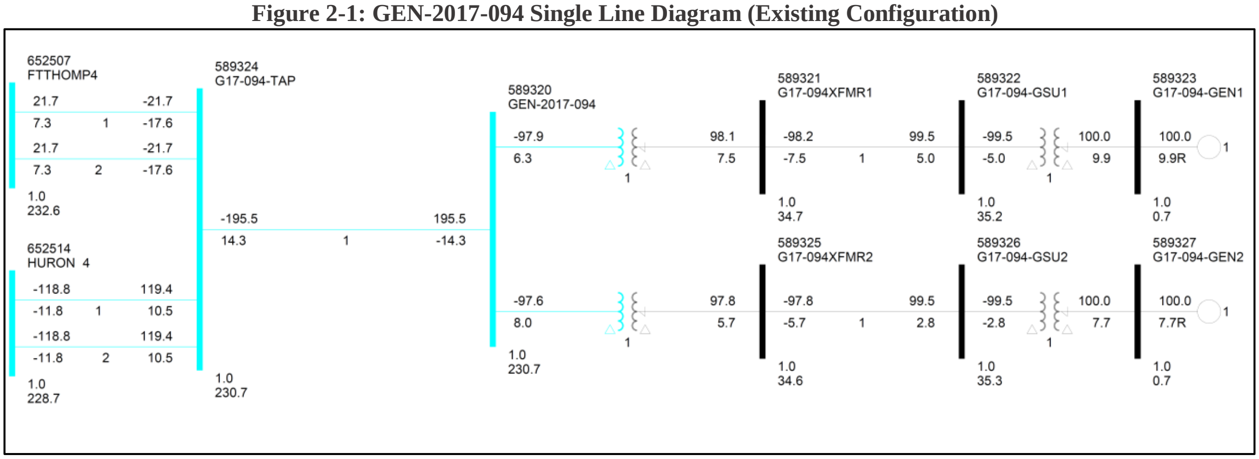
The GEN-2017-094 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a Point of Interconnection (POI) on the Fort Thompson to Huron 230 kV line. At the time of report posting, GEN-2017-094 is an active Interconnection Request with a queue status of "IA FULLY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

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

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

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

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



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

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

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

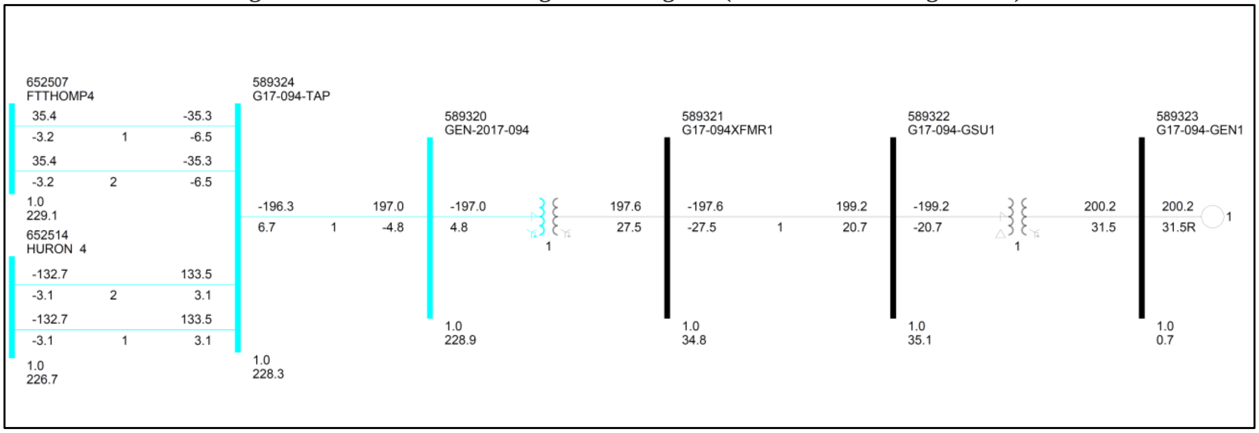


Table 2-2: GEN-2017-094 Modification Request

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

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

3.0 Existing vs Modification Comparison

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

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

3.1 POI Injection Comparison

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

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

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

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

3.2 Turbine Parameters Comparison

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

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

3.3 Equivalent Impedance Comparison Calculation

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

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

4.0 Charging Current Compensation Analysis

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

4.1 Methodology and Criteria

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

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

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

4.2 Results

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

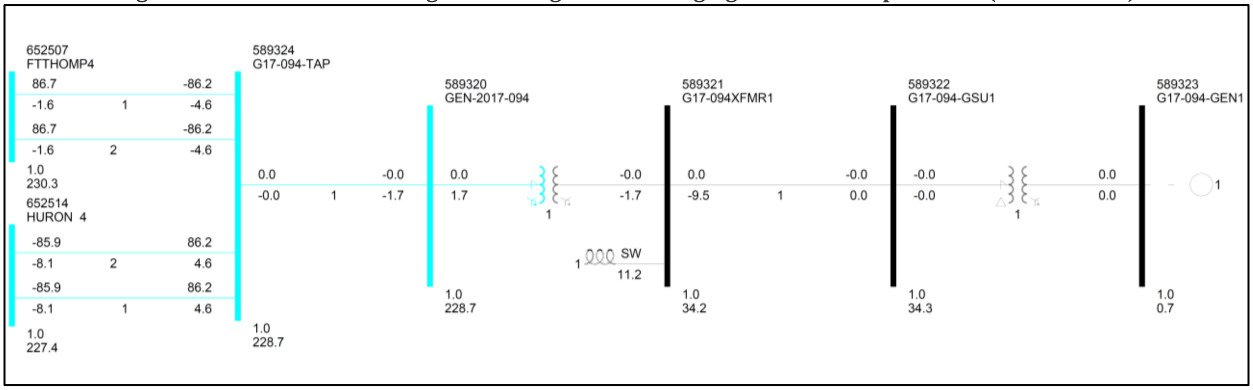
The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission 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-2017-094	589324	G17-094-TAP 230 kV	11.4	11.4

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

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



5.0 Short Circuit Analysis

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

5.1 Methodology

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

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

Table 5-1: Short Circuit Model Parameters

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

5.2 Results

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

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

Table 5-2: POI Short Circuit Results

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

Table 5-3: 25SP Short Circuit Results

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

6.0 Dynamic Stability Analysis

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

6.1 Methodology and Criteria

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

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

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

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

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

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

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2017-094 and other current and prior queued projects in their cluster group[4]. In addition, voltages of five (5) buses away from the POI of GEN-2017-094 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 356 (AMMO), 600 (XEL), 608 (MP), 615 (GRE), 620 (OTP), 627 (ALTW), 635 (MEC), 652 (WAPA), 659 (BEPC-SPP), 661 (MDU), and 680 (DPC) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

6.2 Fault Definitions

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

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

Table 6-1: Fault Definitions

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

Table 6-1 Continued

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

Table 6-1 Continued

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

Table 6-1 Continued

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

Table 6-1 Continued

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

Table 6-1 Continued

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

Table 6-1 Continued

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

Table 6-1 Continued

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

6.3 Results

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

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

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

Table 6-2 continued

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

Table 6-2 continued

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

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

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

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

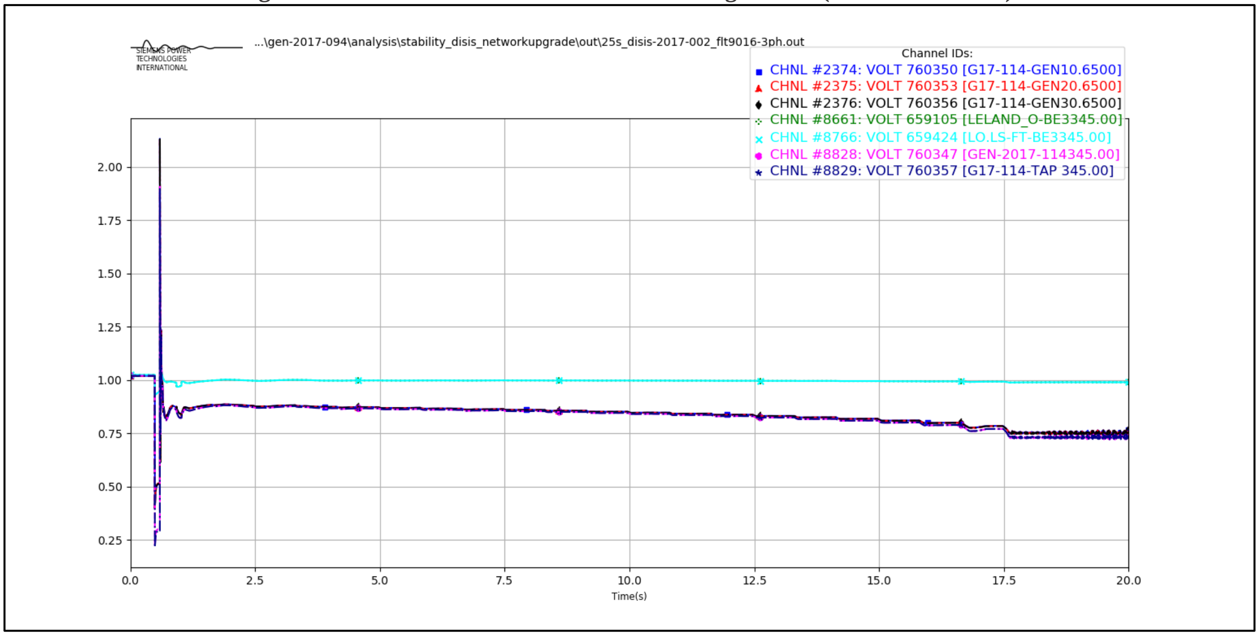
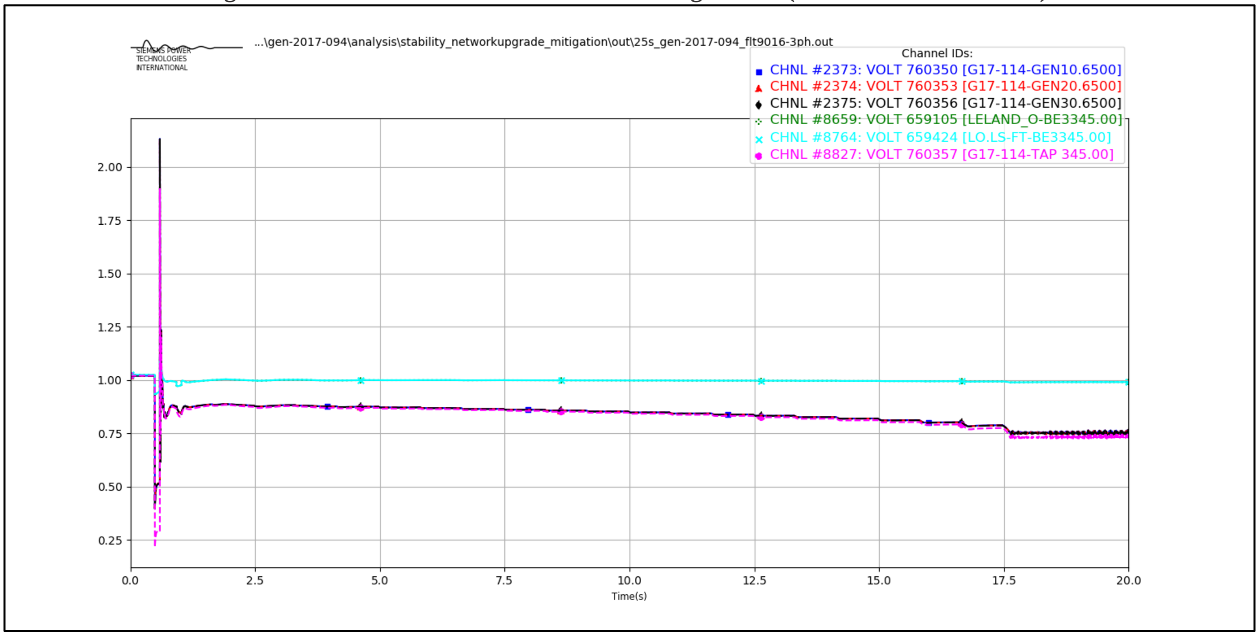


Figure 6-2: FLT9016-3PH GEN-2017-114 Voltage Issues (25SP Modification Case)



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

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

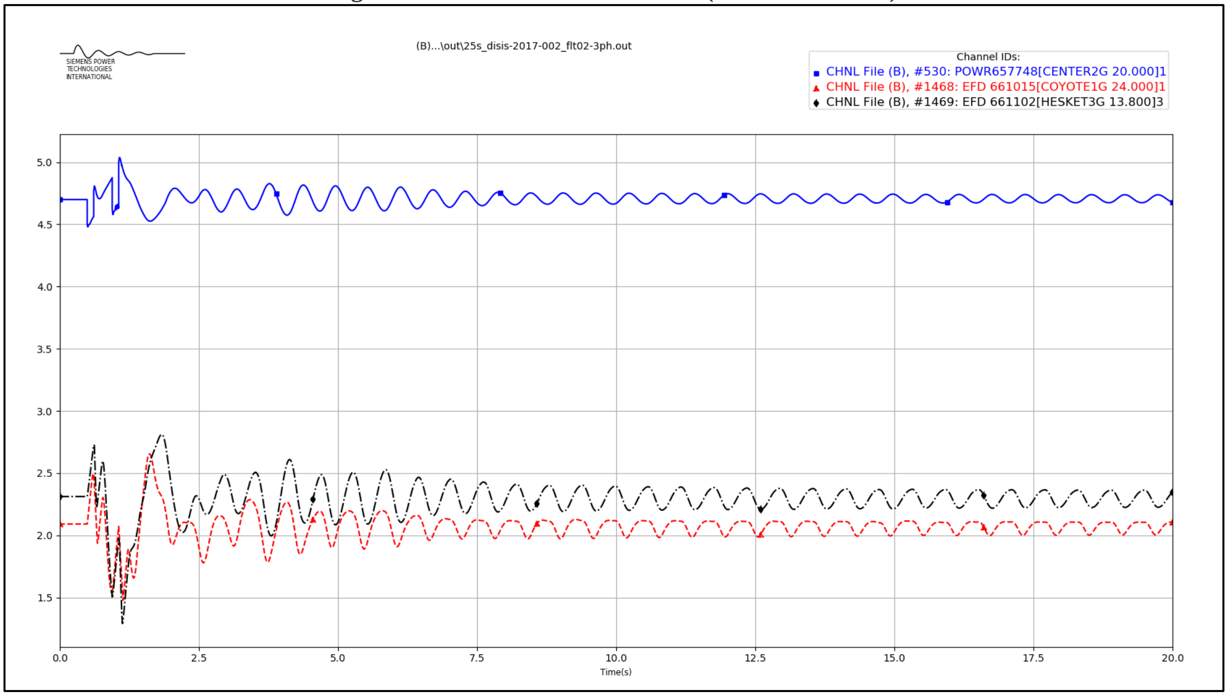
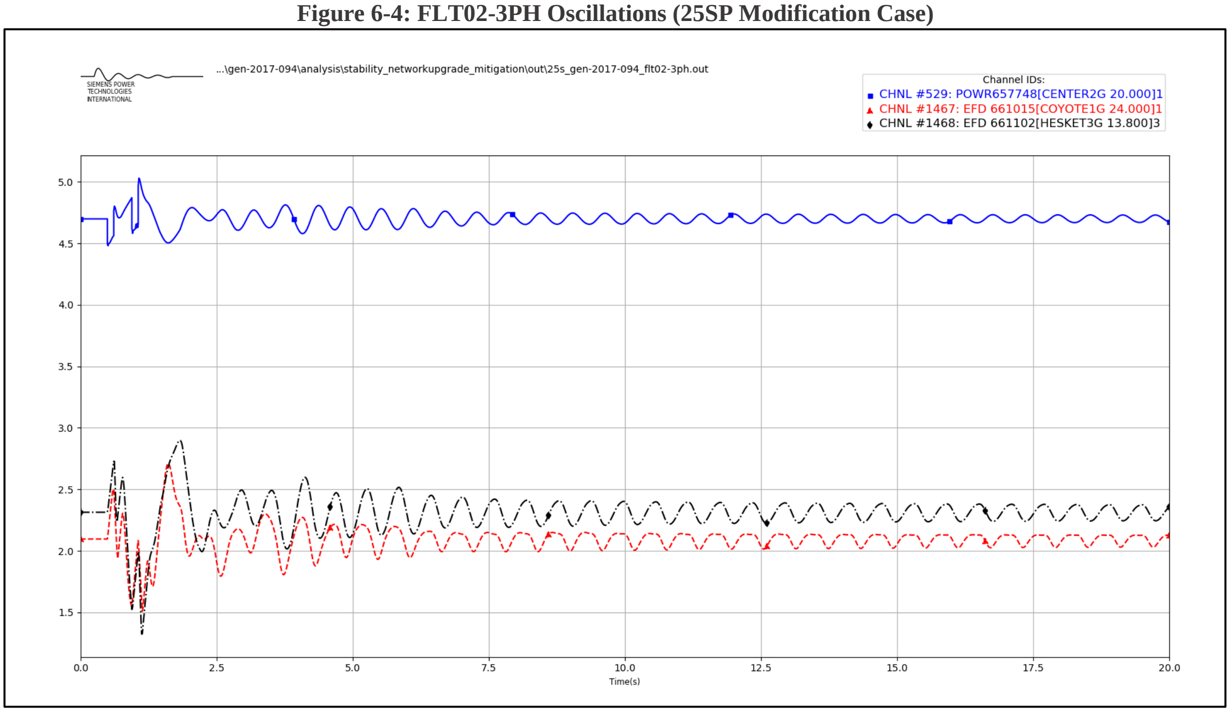


Figure 6-4: FLT02-3PH Oscillations (25SP Modification Case)



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

7.0 Modified Capacity Exceeds GIA Capacity

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

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

7.1 Results

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

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

8.0 Material Modification Determination

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

8.1 Results

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

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

9.0 Conclusions

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

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

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

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

The results of the charging current compensation analysis using the 2025 Summer Peak and 2025 Winter Peak models showed that the GEN-2017-094 project needed a 11.4 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 9.3 MVAr found in the DISIS-2017-001 study[5]. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

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

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

The results of the dynamic stability analysis showed that there were stability issues associated with GEN-2017-114, an interconnection request withdrawn from the SPP Active Queue. As such that issue is no longer relevant. In addition, oscillations were observed for several generation units including CENTER2G (657748), COYOTE1G (661015), and HESKET3G (661102) under multiple contingencies in the DISIS-2017-002 case and the case with the GEN-2017-094 modification. These issues were not attributed to the GEN-2017-094 modification request.

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

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

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

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

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

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