GEN-2017-221

MODIFICATION REQUEST IMPACT STUDY

By SPP Generator Interconnection

Published on February 24, 2025

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
2/24/2025	SPP Staff	Original Version	

CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDICES

EXECUTIVE SUMMARY

Southwest Power Pool performed a Modification Request Impact Study (Study) for GEN-2017-221, an active Generation Interconnection Request (GIR) with a Point of Interconnection (POI) at the Buffalo Flats 345 kV Substation.

The GEN-2017-221 project interconnects in the WESTAR (WERE) control area with a capacity of 152 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2017-221 to change the BESS configuration to 40 x PE FS4200M 4.2 MVA for a total capacity of 154.28 MW. The inverters are rated at 3.82 MW, and use a Power Plant Controller (PPC) to limit the total power injected into the POI. The generating capacity for GEN-2017-221 (152 MW) and the total capability (154.28MW) exceed its Generator Interconnection Agreement (GIA) Interconnection Service amount, 152 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, main substation transformer, and reactive power devices. The existing and modified configurations for GEN-2017-221 are shown in Table ES-2.

Table ES-1: GEN-2017-221 Existing Configuration

REQUEST	POINT OF INTERCONNECTION	EXISTING GENERATOR CONFIGURATION	GIA CAPACITY (MW)
GEN-2017-221	Buffalo Flats 345 kV Substation (527482)	40 x PE FS4200M 4.2 MVA BESS	152 MW

Table ES-2: GEN-2017-221 Modification Request

Facility	Modification Configuration		
Point of Interconnection	Buffalo Flats 345 kV		
Configuration/Capacity	152MW BESS at POI		
Generation Interconnection Line	Length = 2.7 miles (New) R = 0.000136 pu X = 0.001436 pu B = 0.021889 pu	Length = 14.6 miles (Existing) (NINN1WF7-KINGMAN7) R = 0.00047 pu X = 0.00662 pu B = 0.13783 pu	Length = 46.2 miles (Existing) (KINGMAN7-BUFFALO7) R = 0.00149 pu X = 0.02096 pu B = 0.43611 pu
Main Substation Transformer[1]	354/34.5/13.8 kV 102/136/170 MVA Typical values: Z = 8.5%; X/R = 40		
Equivalent GSU Transformer[1]	PE Equivalent Qty: 40 34.5/0.66 kV 168.0 MVA Winding MVA Z = 9% X/R = 10.3		
Equivalent Collector Line[2]	R = 0.000278 pu X = 0.000328 pu B = 0.001252 pu		
Generator Dynamic Model[3] & Power Factor	40 x BESS (REGCAU1)[3] x 3.8 MW Leading: 0.918 Lagging: 0.918		
1) X and R based on Winding MVA 2) All pu are on 100 MVA Base 3) DYR stability model name			

SPP determined that the change in inverter manufacturer from General Electric to Power Electronics 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.

SPP performed the analyses using the modification request data based on the DISIS-2018-002/2019-001 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 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-2017-221 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2017-221 POI was no greater than 32.044 kA.

All three-phase fault current levels within 5 buses of the POI with the GEN-2017-221 generator online were below 40 kA.

The dynamic stability analysis was performed using Siemens PTI PSS/E version 34.8.0 software for the two modified study models: 25SP and 25WP. Sixty events were simulated, which included three-phase faults and single-line-to-ground stuck breaker faults.

The results of the dynamic stability analysis showed that there were several existing base case issues found in the original DISIS-2018-002/2019-001 case and the case with the GEN-2017-221 modification. These issues were not attributed to the GEN-2017-221 modification request and detailed in Appendix D.

There were no damping or voltage recovery violations attributed to the GEN-2017-221 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.

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.

[1] Power System Simulator for Engineering

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.

SCOPE OF STUDY

Southwest Power Pool (SPP) performed a Modification Request Impact Study (Study) for GEN-2017-221. 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.

STEADY-STATE ANALYSIS

SPP determined that powerflow should not be performed because the technology type of the request was unchanged with the modification.

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.

STUDY LIMITATIONS

The assessments and conclusions provided in this report are based on assumptions and information provided to SPP by others. While the assumptions and information provided may be appropriate for the purposes of this report, SPP does not guarantee that those conditions assumed will occur. In addition, SPP 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.

PROJECT AND MODIFICATION REQUEST

The GEN-2017-221 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a Point of Interconnection (POI) at the Buffalo Flats 345 kV Substation. At the time of report posting, GEN-2017-221 is an active Interconnection Request with a queue status of "IA FULLY EXECUTED/ON SCHEDULE." GEN-2017-221 is a battery with a maximum summer and winter queue capacity of 152 MW with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).

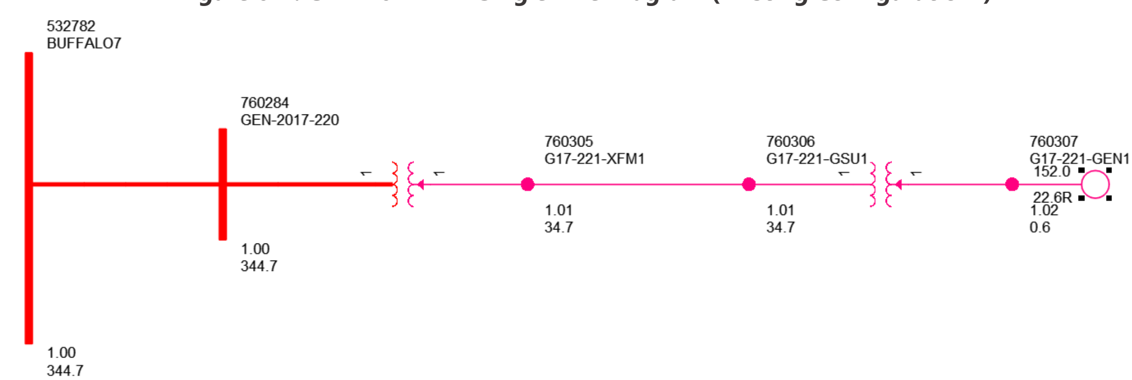
The GEN-2017-221 project is currently in the DISIS-2017-002 cluster.

Figure 0-1 shows the powerflow model single line diagram for the existing GEN-2017-221 configuration using the DISIS-2018-002/2019-001 stability models. The GEN-2017-221 project interconnects in the Westar (WERE) control area with a capacity of 152 MW as shown in Table 0-1 below.

Table 0-1: GEN-2017-221 Existing Configuration

REQUEST	POINT OF INTERCONNECTION	EXISTING GENERATOR CONFIGURATION	GIA CAPACITY (MW)
GEN-2017-221	Buffalo Flats 345 kV (532782)	76 x Parker 2 MW/2.2 MVA	152

Figure 0-1: GEN-2017-221 Single Line Diagram (Existing Configuration*)



*based on the DISIS-2018-002/2019-001 stability models

This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2017-221 to an inverter configuration of 40 x PE FP4200M2 batteries at 3.857 MW per unit for a total capacity of 154.28 MW. This generating capacity for GEN-2017-221 (154.28 MW) and the total capability (154.28 MW) exceed its Generator Interconnection Agreement (GIA) Interconnection Service amount, 152 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, main substation transformer, and reactive power devices. Figure 0-2 shows the powerflow model single line diagram for the GEN-2017-221 modification. The existing and modified configurations for GEN-2017-221 are shown in

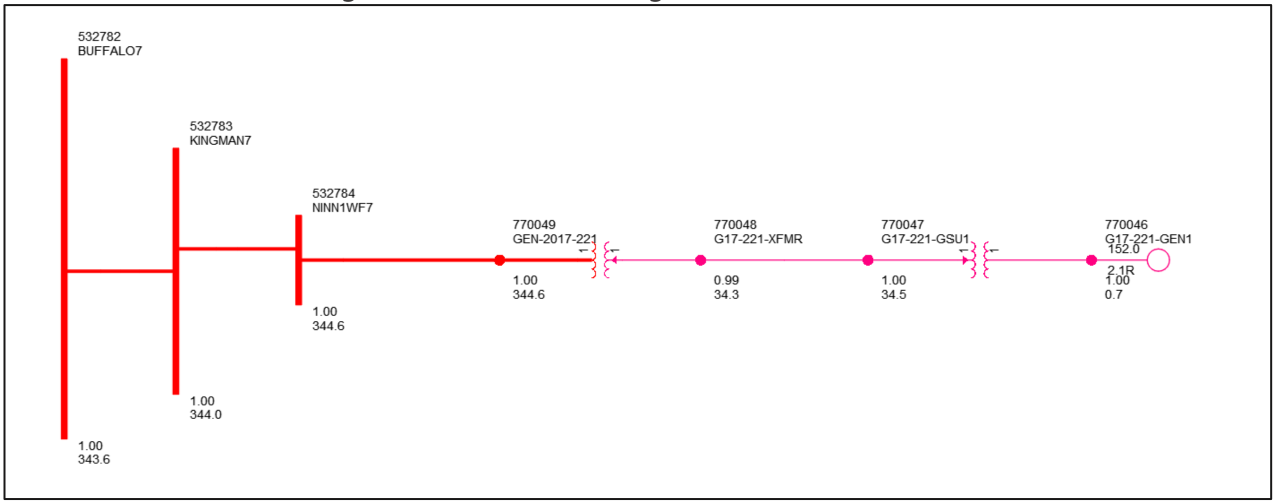


Table 0-2.

Figure 0-2: GEN-2017-221 Single Line Diagram (Modification Configuration)

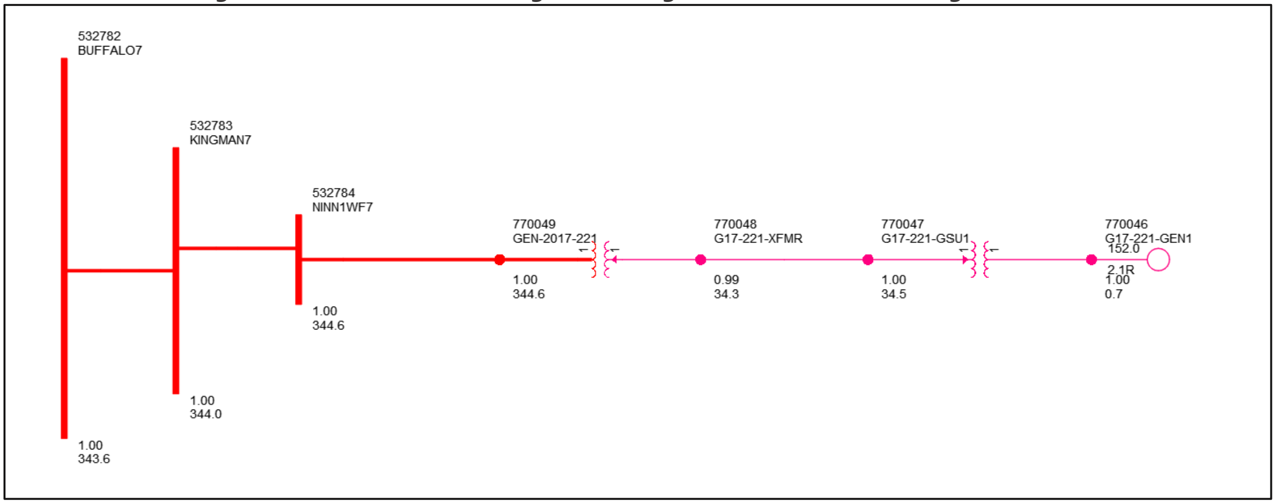


Table 0-2: GEN-2017-221 Modification Request

Facility	Modification Configuration

Point of Interconnection	Buffalo Flats 345 kV		
Configuration/Capacity	152MW BESS at POI		
Generation Interconnection Line	Length = 2.7 miles (New) R = 0.000136 pu X = 0.001436 pu B = 0.021889 pu	Length = 14.6 miles (Existing) (NINN1WF7-KINGMAN7) R = 0.00047 pu X = 0.00662 pu B = 0.13783 pu	Length = 46.2 miles (Existing) (KINGMAN7-BUFFALO7) R = 0.00149 pu X = 0.02096 pu B = 0.43611 pu
Main Substation Transformer[1]	354/34.5/13.8 kV 102/136/170 MVA Typical values: Z = 8.5%; X/R = 40		
Equivalent GSU Transformer[1]	PE Equivalent Qty: 40 34.5/0.66 kV 168.0 MVA Winding MVA Z = 9% X/R = 10.3		
Equivalent Collector Line[2]	R = 0.000278 pu X = 0.000328 pu B = 0.001252 pu		
Generator Dynamic Model[3] & Power Factor	40 x BESS (REGCAU1)[3] x 3.8 MW Leading: 0.918 Lagging: 0.918		
1) X and R based on Winding MVA 2) All pu are on 100 MVA Base 3) DYR stability model name			

EXISTING VERSUS MODIFICATION COMPARISON

To determine which analyses are required for the Study, the differences between the existing configuration and the requested modification were evaluated. SPP performed this comparison and the resulting analyses using a set of modified study models developed based on the modification request data and the DISIS-2018-002/2019-001 study models.

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

STABILITY MODEL PARAMETERS COMPARISON

SPP determined that short circuit and dynamic stability analyses were required because of the inverter change from General Electric to Power Electronic. 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.

EQUIVALENT IMPEDANCE COMPARISON CALCULATION

As the inverter 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.

SHORT CIRCUIT ANALYSIS

A short circuit study was performed using the 25SP model for GEN-2017-221. The detailed results of the short circuit analysis are provided in Appendix B.

METHODOLOGY

The short circuit analysis included applying a three-phase fault on buses up to five levels away from the 345 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels in the transmission system with and without GEN-2017-221 online.

SPP created a short circuit model using the 25SP DISIS-2018-002/2019-001 stability study model by adjusting the GEN-2017-221 short circuit parameters consistent with the modification data. The adjusted parameters are shown in Table 0-1 below.

Table 0-1: Short Circuit Model Parameters*

PARAMETER	VALUE BY GENERATOR BUS#
	527482
Machine MVA Base	4.2
R (pu)	0.0
X'' (pu)	0.893

*pu values based on Machine MVA Base

RESULTS

The results of the short circuit analysis for the 25SP model are summarized in ase fault current was about 4.89% and 0.27 kA.

Table 0-1 and

Table 0-2. The GEN-2017-221 POI bus (Buffalo Flats - 532782) fault current magnitudes are provided in ase fault current was about 4.89% and 0.27 kA.

Table 0-1 showing a maximum fault current of 20.108 kA with the GEN-2017-221 project online.

Table 0-2 shows the maximum fault current magnitudes and fault current increases with the GEN-2017-221 project online.

The maximum fault current calculated within five buses of the GEN-2017-221 POI (including the POI bus) was less than 40 kA for the 25SP model.

The maximum GEN-2017-221 contribution to three-phase fault current was about 4.89% and 0.27 kA.

Table 0-1: POI Short Circuit Results

CASE	GEN-OFF CURRENT (KA)	GEN-ON CURRENT (KA)	MAX KA CHANGE	MAX %CHANGE
25SP	20.108	20.285	0.177	0.88%

Table 0-2: 25SP Short Circuit Results

VOLTAGE (KV)	MAX. CURRENT (KA)	MAX KA CHANGE	MAX %CHANGE
69	19.607	0.009	0.05%
115	21.885	0.014	0.06%
230	21.658	0.003	0.01%
345	31.731	0.27	4.89%
Max	31.731	0.27	4.89%

DYNAMIC STABILITY ANALYSIS

SPP performed a dynamic stability analysis to identify the impact of the inverter configuration change and other modifications to GEN-2017-221. The analysis was performed according to SPP's Disturbance Performance Requirements[2]. The modification details are described in the Project and Modification Request section and the dynamic modeling data is provided in Appendix A. The existing base case issues and simulation plots can be found in Appendix D.

METHODOLOGY AND CRITERIA

The dynamic stability analysis was performed using models developed with the requested GEN-2017-221 configuration of 40 x PE FP4200M2 4.2 MVA BESS (REGCA1). This stability analysis was performed using PTI's PSS/E version 34.8.0 software.

The modifications requested for the GEN-2017-221 project were used to create modified stability models for this impact study based on the DISIS-2018-002/2019-001 stability study models:

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

The modified dynamic model data for the GEN-2017-221 project is provided in Appendix A. The modified powerflow 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 pre-existing issues that are not attributed to the modification request:

1. Updated the GEN-2016-021 bus numbers and dynamic data.
2. Disabled protective relays in the base stability models. In addition disabled the following busses' frequency relays: 534020, 534021, 534022, 534023, 534033
3. Disabled the voltage relay between busses 602057 and 667085

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2017-221 and other current and prior queued projects in their cluster group[3]. In addition, voltages of five (5) buses away from the POI of GEN-2017-221 were monitored and plotted. The machine rotor angle for synchronous machines and speed for

---

[2] SPP Disturbance Performance Requirements: https://www.spp.org/documents/28859/spp%20disturbance%20performance%20requirements%20(twg%20approved).pdf

[3] Based on the DISIS-2018-002/2019-001 Cluster Groups

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.

FAULT DEFINITIONS

SPP developed and simulated faults for GEN-2017-221 using the modified study models. The new set of faults were simulated using the modified study models. The fault events included three-phase faults 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 pu. The simulated faults are listed and described in

Table 0-1 below. These contingencies were applied to the modified 25SP and 25WP models.

Table 0-1: GEN-2017-221 Fault Definitions

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT9001-3PH	P1_2	3 phase fault on the GEN-2017-220 (760284) to BUFFALO7 (532782) 345 kV line CKT 1, near GEN-2017-220. a. Apply fault at the GEN-2017-220 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1_2	3 phase fault on the BUFFALO7 (532782) to WICHITA7 (532796) 345 kV line CKT 1, near BUFFALO7. a. Apply fault at the BUFFALO7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1_2	3 phase fault on the BUFFALO7 (532782) to WICHITA7 (532796) 345 kV line CKT 2, near BUFFALO7. a. Apply fault at the BUFFALO7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9004-3PH	P1_2	3 phase fault on the WICHITA7 (532796) to G14-001-TAP (562476) 345 kV line CKT 1, near WICHITA7. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1_2	3 phase fault on the G14-001-TAP (562476) to GEN-2014-001 (583850) 345 kV line CKT 1, near G14-001-TAP. a. Apply fault at the G14-001-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.
FLT9006-3PH	P1_2	3 phase fault on the G14-001-TAP (562476) to EMPEC 7 (532768) 345 kV line CKT 1, near G14-001-TAP. a. Apply fault at the G14-001-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.
FLT9007-3PH	P1_2	3 phase fault on the WICHITA7 (532796) to VIOLA 7 (532798) 345 kV line CKT 1, near WICHITA7. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1_2	3 phase fault on the VIOLA 7 (532798) to G16-153-TAP (588364) 345 kV line CKT 1, near VIOLA 7. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	P1_2	3 phase fault on the VIOLA 7 (532798) to G18-128-TAP (763421) 345 kV line CKT 1, near VIOLA 7. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 6 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 20 cycles, then trip the line in (b) and remove fault.
FLT90010-3PH	P1_2	3 phase fault on the 45TH ST4 (533074) to COWSKIN4 (533038) 138 kV line CKT 1, near 45TH ST4. a. Apply fault at the 45TH ST4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		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.
FLT90011-3PH	P1_2	3 phase fault on the 45TH ST4 (533074) to EVANS S4 (533041) 138 kV line CKT 1, near 45TH ST4. a. Apply fault at the 45TH ST4 138 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.
FLT90012-3PH	P1_2	3 phase fault on the EVANS S4 (533041) to LAKERDG4 (533053) 138 kV line CKT 1, near EVANS S4. a. Apply fault at the EVANS S4 138 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.
FLT90013-3PH	P1_2	3 phase fault on the EVANS S4 (533041) to EVANS N4 (533040) 138 kV line CKT Z1, near EVANS S4. a. Apply fault at the EVANS S4 138 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.
FLT90014-3PH	P1_2	3 phase fault on the EVANS S4 (533041) to EVANS N4 (533040) 138 kV line CKT Z2, near EVANS S4. a. Apply fault at the EVANS S4 138 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.
FLT90015-3PH	P1_2	3 phase fault on the EVANS N4 (533040) to SG12COL4 (533065) 138 kV line CKT 1, near EVANS N4. a. Apply fault at the EVANS N4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 6 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 20 cycles, then trip the line in (b) and remove fault.
FLT90016-3PH	P1_2	3 phase fault on the EVANS N4 (533040) to GEN-2018-057 (762922) 138 kV line CKT 1, near EVANS N4. a. Apply fault at the EVANS N4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		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.
FLT90017-3PH	P1_2	3 phase fault on the EVANS N4 (533040) to MAIZE 4 (533054) 138 kV line CKT 1, near EVANS N4. a. Apply fault at the EVANS N4 138 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.
FLT90018-3PH	P1_2	3 phase fault on the EVANS N4 (533040) to GEN-2017-068 (589060) 138 kV line CKT 1, near EVANS N4. a. Apply fault at the EVANS N4 138 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.
FLT90019-3PH	P1_2	3 phase fault on the EVANS N4 (533040) to GEN-2017-179 (760620) 138 kV line CKT 1, near EVANS N4. a. Apply fault at the EVANS N4 138 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.
FLT90020-3PH	P1_2	3 phase fault on the EVANS N4 (533040) to GEN-2017-226 (760641) 138 kV line CKT 1, near EVANS N4. a. Apply fault at the EVANS N4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 6 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 20 cycles, then trip the line in (b) and remove fault.
FLT90021-3PH	P1_2	3 phase fault on the WICHITA7 (532796) to RENO 7 (532771) 345 kV line CKT 1, near WICHITA7. a. Apply fault at the WICHITA7 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.
FLT90022-3PH	P1_2	3 phase fault on the RENO 7 (532771) to G16-111-TAP (587884) 345 kV line CKT 1, near RENO 7. a. Apply fault at the RENO 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		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.
FLT90023-3PH	P1_2	3 phase fault on the NINN1WF7 (532784) to PRATTWF7 (532785) 345 kV line CKT 1, near NINN1WF7. a. Apply fault at the NINN1WF7 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.
FLT90024-3PH	P1_2	3 phase fault on the WICHITA7 (532796) to BENTON 7 (532791) 345 kV line CKT 1, near WICHITA7. a. Apply fault at the WICHITA7 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.
FLT90025-3PH	P1_2	3 phase fault on the NINN1WF7 (532784) to KINGMAN7 (532783) 345 kV line CKT 1, near NINN1WF7. a. Apply fault at the NINN1WF7 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.
FLT90026-3PH	P1_2	3 phase fault on the KINGMAN7 (532783) to BUFFALO7 (532782) 345 kV line CKT 1, near KINGMAN7. a. Apply fault at the KINGMAN7 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.
FLT90027-3PH	P1_2	3 phase fault on the BENTON 7 (532791) to ROSEHIL7 (532794) 345 kV line CKT 1, near BENTON 7. a. Apply fault at the BENTON 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT90028-3PH	P1_2	3 phase fault on the BENTON 7 (532791) to WOLFCRK7 (532797) 345 kV line CKT 1, near BENTON 7. a. Apply fault at the BENTON 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		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.
FLT90029-3PH	P1_2	3 phase fault on the WOLFCRK7 (532797) to ROSEHIL7 (532794) 345 kV line CKT 1, near WOLFCRK7. a. Apply fault at the WOLFCRK7 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.
FLT90030-3PH	P1_2	3 phase fault on the BUFFALO7 (532782) to THISTLE7 (539801) 345 kV line CKT 1, near BUFFALO7. a. Apply fault at the BUFFALO7 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.
FLT90031-3PH	P1_2	3 phase fault on the BUFFALO7 (532782) to THISTLE7 (539801) 345 kV line CKT 2, near BUFFALO7. a. Apply fault at the BUFFALO7 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.
FLT90032-3PH	P1_2	3 phase fault on the THISTLE7 (539801) to DGRASSE7 (515852) 345 kV line CKT 1, near THISTLE7. a. Apply fault at the THISTLE7 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.
FLT90033-3PH	P1_2	3 phase fault on the THISTLE7 (539801) to DGRASSE7 (515852) 345 kV line CKT 2, near THISTLE7. a. Apply fault at the THISTLE7 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.
FLT90034-3PH	P1_2	3 phase fault on the THISTLE7 (539801) to CLARKCOUNTY7 (539800) 345 kV line CKT 1, near THISTLE7. a. Apply fault at the THISTLE7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		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.
FLT90035-3PH	P1_2	3 phase fault on the THISTLE7 (539801) to CLARKCOUNTY7 (539800) 345 kV line CKT 2, near THISTLE7. a. Apply fault at the THISTLE7 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.
FLT90036-3PH	P1_2	3 phase fault on the THISTLE7 (539801) to GEN-2018-049 (762834) 345 kV line CKT 1, near THISTLE7. a. Apply fault at the THISTLE7 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.
FLT90037-3PH	P1_2	3 phase fault on the THISTLE7 (539801) to GEN-2017-018 (588630) 345 kV line CKT 1, near THISTLE7. a. Apply fault at the THISTLE7 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.
FLT90038-3PH	P1_2	3 phase fault on the FLATRDG4 (539638) to FLATRWD4 (539631) 138 kV line CKT 1, near FLATRDG4. a. Apply fault at the FLATRDG4 138 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.
FLT90039-3PH	P1_2	3 phase fault on the FLATRDG4 (539638) to THISTLE4 (539804) 138 kV line CKT 1, near FLATRDG4. a. Apply fault at the FLATRDG4 138 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.
FLT90040-3PH	P1_2	3 phase fault on the FLATRDG4 (539638) to BARBER 4 (539674) 138 kV line CKT 1, near FLATRDG4. a. Apply fault at the FLATRDG4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		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.
FLT90041-3PH	P1_2	3 phase fault on the FLATRDG4 (539638) to HARPER 4 (539668) 138 kV line CKT 1, near FLATRDG4. a. Apply fault at the FLATRDG4 138 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.
FLT90042-3PH	P1_3	3 phase fault on the THISTLE7 345kV (539801)/ 138 kV (539804)/ 13.8 kV (539802) XFMR CKT 1, near THISTLE7 345 kV. a. Apply fault at the THISTLE7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT90043-3PH	P1_3	3 phase fault on the VIOLA 7 345kV (532798)/ 138 kV (533075)/ 13.8 kV (532832) XFMR CKT 1, near VIOLA 7 345 kV. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT90044-3PH	P1_3	3 phase fault on the THISTLE7 345kV (539801)/ 138 kV (539804)/ 13.8 kV (999532) XFMR CKT 1, near THISTLE7 345 kV. a. Apply fault at the THISTLE7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT90045-3PH	P1_3	3 phase fault on the EVANS S4 138kV (533041)/ 13.8 kV (532724) XFMR CKT 1, near EVANS S4 138 kV. a. Apply fault at the EVANS S4 138 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT90046-3PH	P1_3	3 phase fault on the EVANS S4 138kV (533041)/ 13.8 kV (532723) XFMR CKT 1, near EVANS S4 138 kV. a. Apply fault at the EVANS S4 138 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT90047-3PH	P1_3	3 phase fault on the EVANS S4 138kV (533041)/ 18 kV (532725) XFMR CKT 1, near EVANS S4 138 kV. a. Apply fault at the EVANS S4 138 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT90048-3PH	P1_3	3 phase fault on the WICHITA7 345kV (532796)/ 138 kV (533040)/ 13.8 kV (532830) XFMR CKT 1, near WICHITA7 345 kV. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT90049-3PH	P1_3	3 phase fault on the WICHITA7 345kV (532796)/ 138 kV (533040)/ 13.8 kV (532829) XFMR CKT 1, near WICHITA7 345 kV. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT90050-3PH	P1_3	3 phase fault on the BENTON 7 345kV (532791)/ 138 kV (532986)/ 13.8 kV (532822) XFMR CKT 1, near BENTON 7 345 kV. a. Apply fault at the BENTON 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT90051-3PH	P1_3	3 phase fault on the BENTON 7 345kV (532791)/ 138 kV (532986)/ 13.8 kV (532821) XFMR CKT 1, near BENTON 7 345 kV. a. Apply fault at the BENTON 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT90052-3PH	P1_3	3 phase fault on the RENO 7 345kV (532771)/ 115 kV (533416)/ 14.4 kV (532807) XFMR CKT 1, near RENO 7 345 kV. a. Apply fault at the RENO 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT90053-3PH	P1_3	3 phase fault on the RENO 7 345kV (532771)/ 115 kV (533416)/ 14.4 kV (532810) XFMR CKT 1, near RENO 7 345 kV. a. Apply fault at the RENO 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT90054-3PH	P1_3	3 phase fault on the NINN1WF7 345kV (532784)/ 34.5 kV (534000)/ 13.8 kV (534030) XFMR CKT 1, near NINN1WF7 345 kV. a. Apply fault at the NINN1WF7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT90055-3PH	P1_3	3 phase fault on the KINGMAN7 345kV (532783)/ 34.5 kV (534002)/ 13.8 kV (534032) XFMR CKT 1, near KINGMAN7 345 kV. a. Apply fault at the KINGMAN7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT90056-3PH	P1_3	3 phase fault on the KINGMAN7 345kV (532783)/ 34.5 kV (534001)/ 13.8 kV (534031) XFMR CKT 1, near KINGMAN7 345 kV. a. Apply fault at the KINGMAN7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT1001-SLG	P4	*Apply single-phase fault at BUFFALO7 on the 345kV bus after 16 cycles* *a. Trip the BUFFALO7 to KINGMAN7 Transmission Line Ckt 1* *b. Trip the BUFFALO7 to THISTLE7 Transmission Line Ckt 1*
FLT1002-SLG	P4	*Apply single-phase fault at BUFFALO7 on the 345kV bus after 16 cycles* *a. Trip the BUFFALO7 to EVANS N4 Transmission Line Ckt 1* *b. Trip the BUFFALO7 to THISTLE7 Transmission Line Ckt 1*
FLT1003-SLG	P4	*Apply single-phase fault at BUFFALO7 on the 345kV bus after 16 cycles* *a. Trip the BUFFALO7 to WICHITA7 Transmission Line Ckt 1* *b. Trip the BUFFALO7 to EVANS N4 Transmission Line Ckt 1*
FLT1004-SLG	P4	*Apply single-phase fault at BUFFALO7 on the 345kV bus after 16 cycles* *a. Trip the BUFFALO7 to KINGMAN7 Transmission Line Ckt 1* *b. Trip the BUFFALO7 to EVANS N4 Transmission Line Ckt 1*

RESULTS

Table 0-1 shows the relevant results of the fault events simulated for each of the modified cases. Existing DISIS base case issues are documented separately in Appendix D. The associated stability plots are also provided in Appendix D.

Table 0-1: GEN-2017-221 Dynamic Stability Results

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	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
FLT90010-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90011-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90012-3PH	Pass	Pass	Stable	Pass	Pass	Stable

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT90013-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90014-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90015-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90016-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90017-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90018-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90019-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90020-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90021-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90022-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90023-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90024-3PH	Pass	Pass	Stable	Pass	Pass	Stable

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT90025-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90026-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90027-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90028-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90029-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90030-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90031-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90032-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90033-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90034-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90035-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90036-3PH	Pass	Pass	Stable	Pass	Pass	Stable

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT90037-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90038-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90039-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90040-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90041-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90042-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90043-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90044-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90045-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90046-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90047-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90048-3PH	Pass	Pass	Stable	Pass	Pass	Stable

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT90049-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90050-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90051-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90052-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90053-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90054-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90055-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90056-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SLG	Pass	Pass	Stable	Pass	Pass	Stable

The results of the dynamic stability analysis showed that there were several existing base case issues found in the original DISIS-2018-002/2019-001 case and the case with the GEN-2017-221 modification. These issues were not attributed to the GEN-2017-221 modification request and detailed in Appendix D.

There were no damping or voltage recovery violations attributed to the GEN-2017-221 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.

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.

RESULTS

The modified generating capacity of GEN-2017-221 (152 MW) and the total capability (154.28 MW) exceed the GIA Interconnection Service amount, 152 MW, as listed in Appendix A of the GIA. The GEN-2017-221 inverters are rated at 3.857 MW, and use a power plant controller (PPC) to limit the total power injected into the POI.

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.

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.

RESULTS

SPP determined the requested modification is **not a Material Modification** based on the results of this Modification Request Impact Study performed by SPP. SPP evaluated the impact of the requested modification on the prior study results. SPP 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 enough to change the previously studied powerflow conclusions.

This determination implies that any network upgrades already required by GEN-2017-221 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.