



Report on

GEN-2016-030 and GEN-2017-232 Modification Request Impact Study

Revision R1 October 27, 2025

Submitted to
Southwest Power Pool



anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
10/27/2025	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 both GEN-2016-030 and GEN-2017-232, two active Generation Interconnection Requests (GIRs) with a Point of Interconnection (POI) at the Brown 138 kV Substation.

GEN-2016-030 and GEN-2017-232 interconnect in the Oklahoma Gas & Electric (OGE) transmission system with capacities of 100 MW and 52.2 MW respectively. This Study has been requested to evaluate the modification of GEN-2016-030 to change the configuration to 26 x Sungrow SG4400 solar inverters operating at 3.9327 MW for a total assumed dispatch of 102.25 MW. It is also modifying GEN-2017-232 to a configuration of 13 x Sungrow SG4400 solar inverters operating at 4.0925 MW for a total assumed dispatch of 53.2 MW. The inverters for both projects are rated at 4.4 MVA, thus the total generating capabilities exceed their Generator Interconnection Agreement (GIA) Interconnection Service amounts. The injection amounts must be limited to 100 MW and 52.2 MW respectively at the POI as listed in Appendix A of each project's GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

In addition, the modification request included changes to the reactive power devices, auxiliary loads, collection system, generator step-up transformers, main substation transformer, and generation interconnection line for each project. The previously accepted and modified configurations for both GEN-2016-030 and GEN-2017-232 are shown in Table ES-1 below.

Table ES-1: GEN-2016-030 and GEN-2017-232 Modification Requests

Facility	Existing Configuration		Modification Configuration	
	GEN-2016-030	GEN-2017-232	GEN-2016-030	GEN-2017-232
Point of Interconnection	BROWN 4 138 kV (515157)		BROWN 4 138 kV (515157)	
Configuration/Capacity	37 x PE FS2800 2.7 MW (solar) = 99 MW	18 x PE FS3150M (solar) = 52.2 MW	26 x Sungrow SG4400 3.9327 MW (solar) = 102.25 MW [dispatch] Units are rated at 4.4 MVA, PPC in place to limit POI to 100 MW	13 x Sungrow SG4400 4.0925 MW (solar) = 53.2 MW [dispatch] Units are rated at 4.4 MVA, PPC in place to limit POI to 52.2 MW
Generation Interconnection Line	Length = 5 miles R = 0.003360 pu X = 0.019120 pu B = 0.034340 pu Rating MVA = 0 MVA		Length = 0.18 miles R = 0.000096 pu X = 0.000683 pu B = 0.000210 pu Rating MVA = 237 MVA	
Main Substation Transformer ¹	X = 8.997%, R = 0.225%, Winding MVA = 75 MVA, Rating MVA = 125 MVA	X = 8.997%, R = 0.225%, Winding MVA = 36 MVA, Rating MVA = 60 MVA	X12 = 9.0% R12 = 0.225%, X23 = 3.61% R23 = 0.09%, X13 = 12.596% R13 = 0.315%, Winding MVA = 108 MVA, Winding 1, 2, & 3 Rating MVA = 180 MVA	
Equivalent GSU Transformer ¹	Gen 1 Equivalent Qty: 37 X = 6.965%, R = 0.697%, Winding MVA = 111 MVA, Rating MVA = 122.1 MVA	Gen 1 Equivalent Qty: 18 X = 10.595%, R = 1.06%, Winding MVA = 63 MVA, Rating MVA = 63 MVA	Gen 1 Equivalent Qty: 26 X = 7.96%, R = 0.796%, Winding MVA = 114.4 MVA, Rating MVA = 114.4 MVA	Gen 1 Equivalent Qty: 13 X = 7.96%, R = 0.796%, Winding MVA = 57.2 MVA, Rating MVA = 57.2 MVA
Equivalent Collector Line ²	R = 0.010913 pu X = 0.011841 pu B = 0.018470 pu	R = 0.005040 pu X = 0.005035 pu B = 0.004760 pu	R = 0.008760 pu X = 0.011270 pu B = 0.032180 pu	R = 0.011290 pu X = 0.013680 pu B = 0.010900 pu
Generator Dynamic Model ³ & Power Factor	37 x PE FS2800 (PEGEN_HV1008c) ³ Leading: 0.95 Lagging: 0.95	18 x PE FS3150M (PEGEN_HV1008c) ³ Leading: 0.89 Lagging: 0.89	26 x Sungrow SG4400 4.4 MVA (REGCA1) ³ Leading: 0.89 Lagging: 0.89	13 x Sungrow SG4400 4.4 MVA (REGCA1) ³ Leading: 0.93 Lagging: 0.93
Reactive Power Devices	N/A	N/A	1 x 17 MVAR 34.5 kV Capacitor Bank	
Auxiliary Load	N/A	N/A	0.512 MW + 0.168 MVar on 34.5 kV Bus	0.2675 MW + 0.0878 MVar on 34.5 kV Bus

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

SPP determined that steady-state analysis was not required because the modifications to the project were not significant enough to change the previously studied steady-state conclusions. However, SPP determined that the change in manufacturer from PE to Sungrow required short circuit and dynamic stability analyses.

The scope of this study included reactive power analysis, short circuit analysis, and dynamic stability analysis.

Aneden performed the analyses using the modification request data and the DISIS-2021-001 stability study models:

- 2025 Summer Peak (25SP),
- 2025 Winter Peak (25WP)

Aneden reviewed GIRs that shared the same POI, Brown 138 kV, and updated their models as applicable based on SPP's confirmation of the latest project configurations. The two modifications under study, GEN-2016-030 and GEN-2017-232, are the Existing Generating Facilities (EGFs) for the GEN-2020-SR2 and GEN-2024-SR13 Surplus Generating Facility (SGF) projects, respectively. As a result, Aneden included the accepted GEN-2020-SR2 and GEN-2024-SR13 surplus projects in the base models and created two stability scenarios to accommodate the status of both GEN-2020-SR2 and GEN-2024-SR13.

All analyses were performed using the Siemens PTI PSS/E¹ version 34 software and the results are summarized below.

The results of the reactive power analysis using the 25SP model showed that GEN-2016-030 and GEN-2017-232 projects needed a 3.2 MVar and 1.1 MVar shunt reactor respectively on the 34.5 kV bus of the two project substations with the modifications in place. This is a decrease for GEN-2016-030 from the 5.3 MVar found in the previous configuration, and an increase for GEN-2017-232 from the 0.5 MVar calculated. This is necessary to offset the capacitive effect on the transmission network caused by each project's transmission line and collector system during reduced generation conditions. The information gathered from the reactive power analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator (TOP). The applicable reactive power requirements will be further reviewed by the TO and/or TOP.

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 combined GEN-2016-030 and GEN-2017-232 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2016-030 and GEN-2017-232 POI was 0.81 kA. The maximum three-phase fault current level within 5 buses of the POI was 19.8 kA for the 25SP model.

The dynamic stability analysis was performed using Siemens PTI PSS/E version 34.8.1 software for the two modified study models: 25SP and 25WP, each with two dispatch scenarios to ensure all reliability conditions were studied. 48 fault events were simulated, which included three-phase faults and single-line-to-ground stuck breaker faults.

- Scenario 1: GEN-2016-030 and GEN-2017-232 at maximum assumed dispatches, 102.25 MW and 53.2 MW, and the corresponding SGFs, GEN-2020-SR2 and GEN-2024-SR13, disconnected.

¹ Power System Simulator for Engineering

- Scenario 2: The second scenario dispatch has both the EGF and SGF online using the selected Scenario 2 dispatch from the previous GEN-2020-SR2² and GEN-2024-SR13³ surplus reports. The dispatch amounts are detailed in Table 6-1.

The results of the dynamic stability analysis showed several existing base case issues that were found in both the original DISIS-2021-001 models (without GEN-2020-SR2 and GEN-2024-SR13) and in the models with the GEN-2016-030 and GEN-2017-232 modifications (and GEN-2020-SR2 and GEN-2024-SR13) included. These issues were not attributed to the GEN-2016-030 and GEN-2017-232 modification requests and are detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2016-030 and GEN-2017-232 modification requests observed during the simulated faults. Additionally, the projects were 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.

Based on the results of the study, SPP determined that the requested modifications are **not a Material Modification**. The requested modifications do 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 modifications place the generating capacities of the Interconnection Requests at a higher amount than their Interconnection Services, 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 both GIAs.

In accordance with FERC Order No. 827, the generating facilities 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 substations.

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.

² GEN-2020-SR2 Surplus Service Impact Study - June 30, 2021

³ GEN-2024-SR13 Surplus Service Impact Study - October 15, 2024

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 both the GEN-2016-030 and GEN-2017-232 projects. A Modification Request Impact Study is a generation interconnection study performed to evaluate the impacts of modifying the DISIS study assumptions. The determination of the required scope of the study is dependent upon the specific modification requested and how it may impact the results of the DISIS study. Impacting the DISIS results could potentially affect the cost or timing of any Interconnection Request with a later Queue priority date, deeming the requested modification a Material Modification. The criteria sections below include reasoning as to why an analysis was either included or excluded from the scope of study.

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

1.1 Reactive Power Analysis

SPP requires that a reactive power analysis be performed on the requested configuration if it is a non-synchronous resource. The reactive power analysis determines the capacitive effect at the POI caused by the project's collection system and transmission line's capacitance. A shunt reactor size was determined to offset the capacitive effect and maintain zero (0) MVAR injection at the POI while the plant's generators and capacitors were offline.

1.2 Short Circuit Analysis & Stability Analysis

To determine whether stability and short circuit analyses are required, SPP evaluates the difference between the stability models, 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. Dynamic stability analysis was performed on two dispatch scenarios, the first where GEN-2016-030 and GEN-2017-232 was online at 100% of the assumed dispatch with GEN-2020-SR2 and GEN-2024-SR13 offline and disconnected, and the second where both the EGFs and SGFs are online using the selected Scenario 2 dispatches from the GEN-2020-SR2⁴ and GEN-2024-SR13⁵ reports.

1.3 Steady-State Analysis

Steady-state analysis is performed if SPP deems it necessary based on the nature of the requested change. SPP determined that steady-state analysis was not required because the modifications to the project were not significant enough to change the previously studied steady-state conclusions.

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.

⁴ GEN-2020-SR2 Surplus Service Impact Study - June 30, 2021

⁵ GEN-2024-SR13 Surplus Service Impact Study - October 15, 2024

2.0 Project and Modification Request

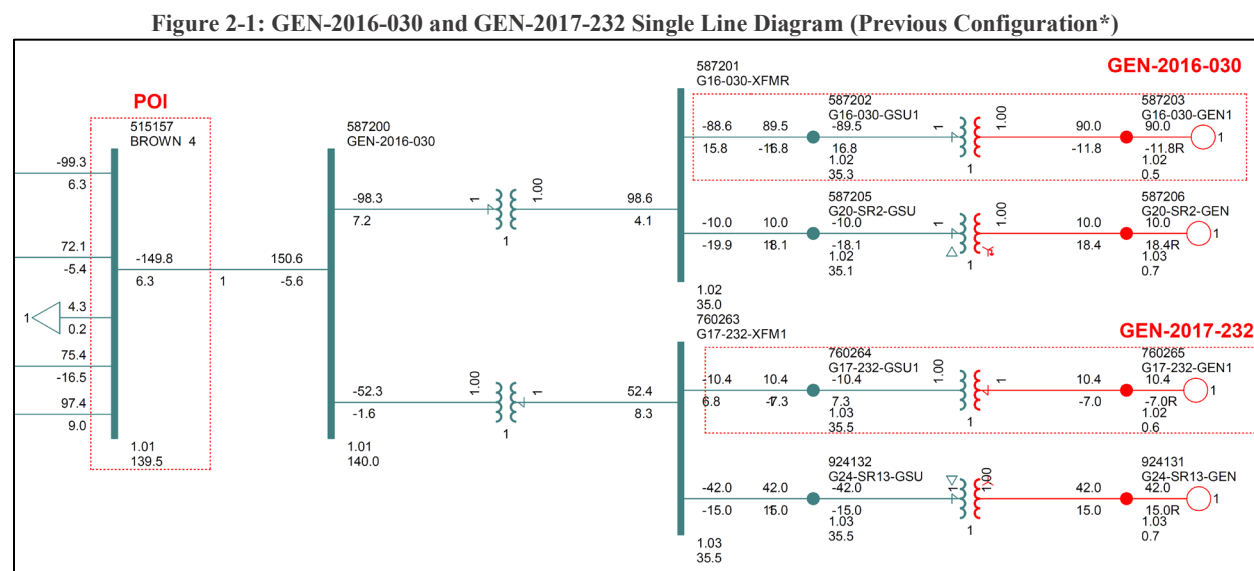
The GEN-2016-030 and GEN-2017-232 Interconnection Customer requested a modification to its Generation Interconnection Requests (GIRs) with a Point of Interconnection (POI) at the Brown 138 kV Substation in the Oklahoma Gas & Electric (OGE) transmission system.

At the time of report posting, the GEN-2016-030 and GEN-2017-232 projects are active Interconnection Requests with a queue status of “IA FULLY EXECUTED/ON SCHEDULE.” GEN-2016-030 and GEN-2017-232 are both solar facilities with a maximum summer and winter queue capacity of 100 MW and 52.2 MW respectively. Both project have Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).

The GEN-2016-030 project is currently in the DISIS-2016-001 cluster, and the GEN-2017-232 project is currently in the DISIS-2017-002 cluster.

Aneden reviewed GIRs that shared the same POI, Brown 138 kV, and updated their models as applicable based on SPP’s confirmation of the latest project configurations. The two modifications under study, GEN-2016-030 and GEN-2017-232, are the Existing Generating Facilities (EGFs) for the GEN-2020-SR2 and GEN-2024-SR13 Surplus Generating Facility (SGF) projects, respectively. As a result, Aneden included the accepted GEN-2020-SR2 and GEN-2024-SR13 surplus projects in the base models and created two stability scenarios to accommodate the status of both GEN-2020-SR2 and GEN-2024-SR13.

Figure 2-1 shows the power flow model single line diagram for the GEN-2016-030 and GEN-2017-232 configurations as modeled in the DISIS-2021-001 25SP stability model with the GEN-2020-SR2 and GEN-2024-SR13 surplus projects included.



*based on the DISIS-2021-001 25SP stability model with the GEN-2020-SR2 and GEN-2024-SR13 surplus projects included

This Study has been requested to evaluate the modification of GEN-2016-030 to change the configuration to 26 x Sungrow SG4400 solar inverters operating at 3.9327 MW for a total assumed dispatch of 102.25 MW. It is also modifying GEN-2017-232 to a configuration of 13 x Sungrow SG4400 solar inverters operating at 4.0925 MW for a total assumed dispatch of 53.2 MW. The inverters for both projects are rated at 4.4 MVA, thus the total generating capabilities exceed their Generator Interconnection Agreement (GIA)

Interconnection Service amounts. The injection amounts must be limited to 100 MW and 52.2 MW respectively at the POI as listed in Appendix A of each project's GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

In addition, the modification request included changes to the reactive power devices, auxiliary loads, collection system, generator step-up transformers, main substation transformer, and generation interconnection line for each project. Figure 2-2 shows the power flow model single line diagram for the GEN-2016-030 and GEN-2017-232 modifications with the GEN-2020-SR2 and GEN-2024-SR13 surplus projects included. The existing and modified configurations for GEN-2016-030 and GEN-2017-232 are shown in Table 2-1 below.

Figure 2-2: GEN-2016-030 and GEN-2017-232 Single Line Diagram (Modification Configuration)

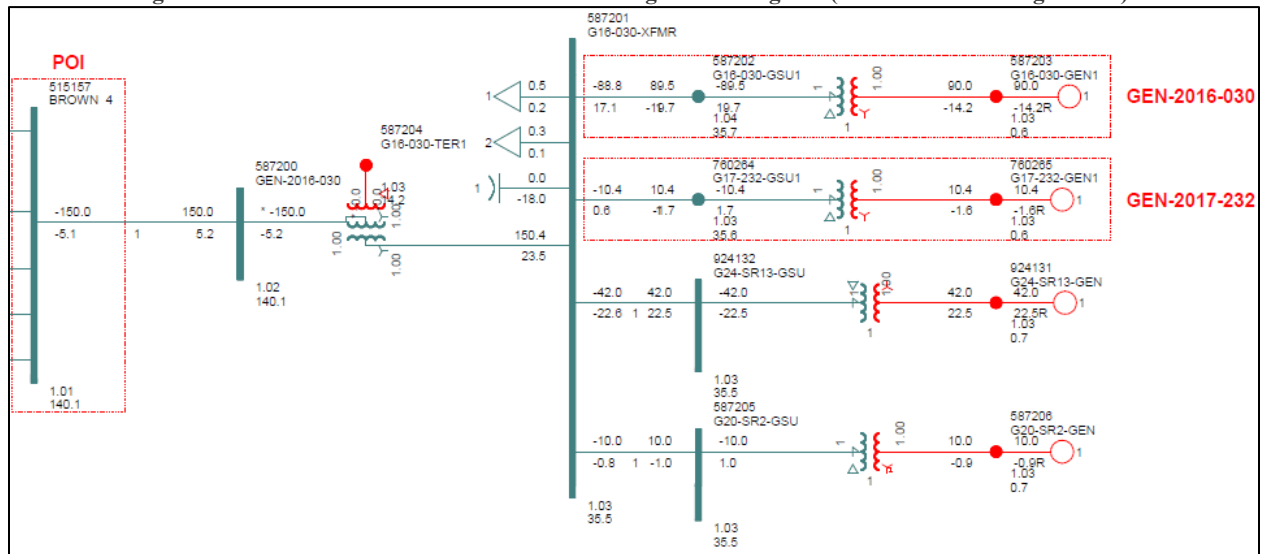


Table 2-1: GEN-2016-030 and GEN-2017-232 Modification Requests

Facility	Existing Configuration		Modification Configuration	
	GEN-2016-030	GEN-2017-232	GEN-2016-030	GEN-2017-232
Point of Interconnection	BROWN 4 138 kV (515157)		BROWN 4 138 kV (515157)	
Configuration/Capacity	37 x PE FS2800 2.7 MW (solar) = 99 MW	18 x PE FS3150M (solar) = 52.2 MW	26 x Sungrow SG4400 3.9327 MW (solar) = 102.25 MW [dispatch] Units are rated at 4.4 MVA, PPC in place to limit POI to 100 MW	13 x Sungrow SG4400 4.0925 MW (solar) = 53.2 MW [dispatch] Units are rated at 4.4 MVA, PPC in place to limit POI to 52.2 MW
Generation Interconnection Line	Length = 5 miles R = 0.003360 pu X = 0.019120 pu B = 0.034340 pu Rating MVA = 0 MVA		Length = 0.18 miles R = 0.000096 pu X = 0.000683 pu B = 0.000210 pu Rating MVA = 237 MVA	
Main Substation Transformer ¹	X = 8.997%, R = 0.225%, Winding MVA = 75 MVA, Rating MVA = 125 MVA	X = 8.997%, R = 0.225%, Winding MVA = 36 MVA, Rating MVA = 60 MVA	X12 = 9.0% R12 = 0.225%, X23 = 3.61% R23 = 0.09%, X13 = 12.596% R13 = 0.315%, Winding MVA = 108 MVA, Winding 1, 2, & 3 Rating MVA = 180 MVA	
Equivalent GSU Transformer ¹	Gen 1 Equivalent Qty: 37 X = 6.965%, R = 0.697%, Winding MVA = 111 MVA, Rating MVA = 122.1 MVA	Gen 1 Equivalent Qty: 18 X = 10.595%, R = 1.06%, Winding MVA = 63 MVA, Rating MVA = 63 MVA	Gen 1 Equivalent Qty: 26 X = 7.96%, R = 0.796%, Winding MVA = 114.4 MVA, Rating MVA = 114.4 MVA	Gen 1 Equivalent Qty: 13 X = 7.96%, R = 0.796%, Winding MVA = 57.2 MVA, Rating MVA = 57.2 MVA
Equivalent Collector Line ²	R = 0.010913 pu X = 0.011841 pu B = 0.018470 pu	R = 0.005040 pu X = 0.005035 pu B = 0.004760 pu	R = 0.008760 pu X = 0.011270 pu B = 0.032180 pu	R = 0.011290 pu X = 0.013680 pu B = 0.010900 pu
Generator Dynamic Model ³ & Power Factor	37 x PE FS2800 (PEGEN_HV1008c) ³ Leading: 0.95 Lagging: 0.95	18 x PE FS3150M (PEGEN_HV1008c) ³ Leading: 0.89 Lagging: 0.89	26 x Sungrow SG4400 4.4 MVA (REGCA1) ³ Leading: 0.89 Lagging: 0.89	13 x Sungrow SG4400 4.4 MVA (REGCA1) ³ Leading: 0.93 Lagging: 0.93
Reactive Power Devices	N/A	N/A	1 x 17 MVAR 34.5 kV Capacitor Bank	
Auxiliary Load	N/A	N/A	0.512 MW + 0.168 MVAR on 34.5 kV Bus	0.2675 MW + 0.0878 MVAR on 34.5 kV Bus

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

3.0 Existing vs Modification Comparison

To determine which analyses are required for the Study, the differences between the previously accepted 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-2021-001 stability study models. The analysis was completed using PSS/E version 34 software.

The methodology and results of the comparisons are described below.

3.1 Stability Model Parameters Comparison

SPP determined that short circuit and dynamic stability analyses were required because of the inverter change from PE to Sungrow turbines. This is because the short circuit contribution and stability responses of the existing configurations and the requested modification configurations may differ. The generator dynamic model for the modification can be found in Appendix A.

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

3.2 Equivalent Impedance Comparison Calculation

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

4.0 Reactive Power Analysis

The reactive power analysis was performed for both GEN-2016-030 and GEN-2017-232 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

To determine the shunt reactor sizes required to compensate for the current charging attributed to the modification requests, the shunt sizes required from the GEN-2020-SR2 and GEN-2024-SR13 surplus studies were placed first. Once the shunt sizes for the SGFs were placed, the GEN-2016-030 and GEN-2017-232 incremental shunt reactor sizes were then calculated.

For each of the shunt reactor sizes calculated, all project generators, capacitors, and auxiliary/station service loads were switched offline while other collector system elements remained in-service. Two shunt reactors (one for each modification project) were tested at the project's collection substation 34.5 kV bus to set the MVar injection at the POI to 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 reactive power analysis using the modification request data based on the 25SP DISIS-2021-001 stability study model.

4.2 Results

The results from the analysis showed that the GEN-2016-030 and GEN-2017-232 projects needed approximately 3.2 MVar and 1.1 MVar respectively of compensation at their collector substations to reduce the MVar injection at the POI to zero with the SGF reactors in place. This is a decrease for GEN-2016-030 from the 5.3 MVar found in the previous configuration, and an increase for GEN-2017-232 from the 0.5 MVar calculated. The final shunt reactor requirements are shown in Table 4-1. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVar to approximately zero with the previous configuration. Figure 4-2 illustrates the shunt reactor size needed to reduce the POI MVar to approximately zero with the updated topology.

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

Table 4-1: Shunt Reactor Sizes for Reactive Power Analysis

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVar)
			25SP
GEN-2016-030	515157	BROWN 138kV	3.2
GEN-2017-232	515157	BROWN 138kV	1.1

Figure 4-1: GEN-2016-030 and GEN-2017-232 Single Line Diagram (Previous Configuration)

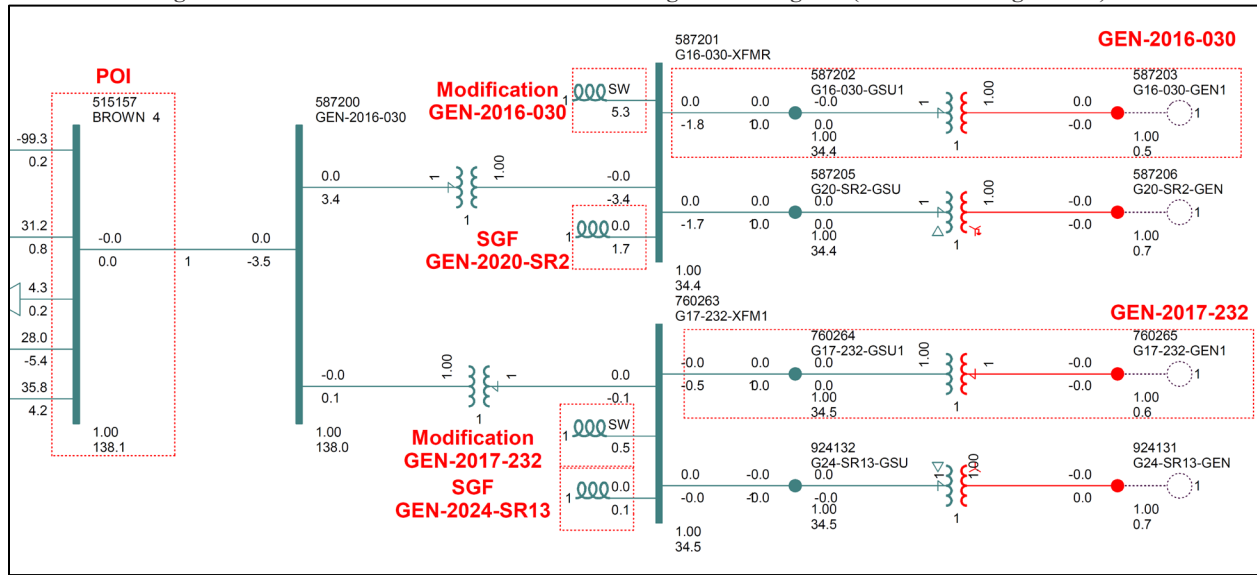
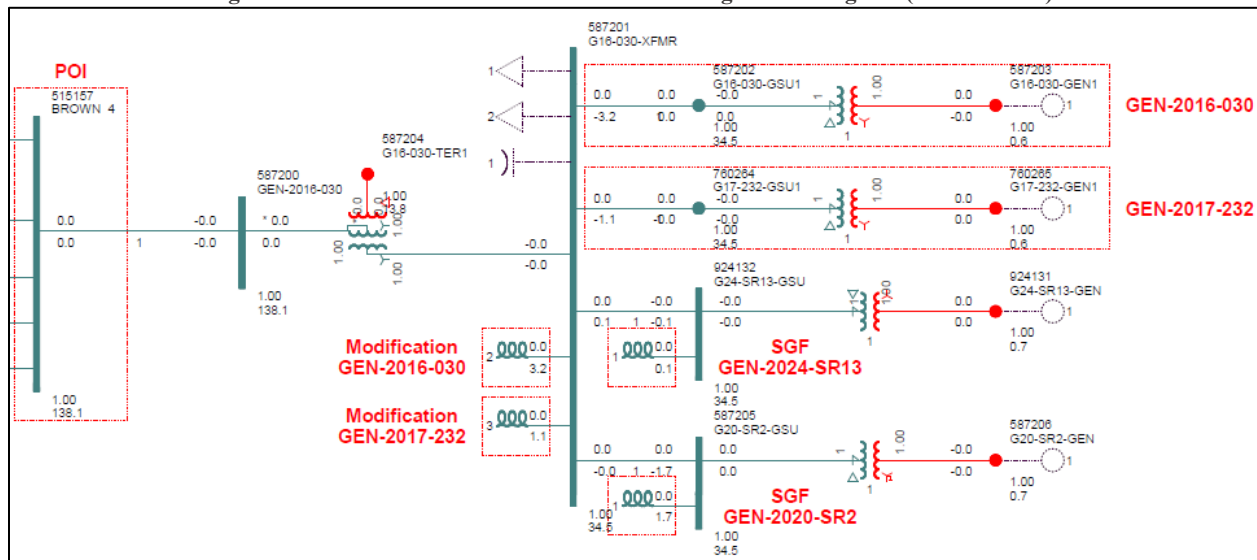


Figure 4-2: GEN-2016-030 and GEN-2017-232 Single Line Diagram (Modification)



5.0 Short Circuit Analysis

Aneden performed a short circuit study using the 25SP model for GEN-2016-030 and GEN-2017-232 to determine the maximum fault current requiring interruption by protective equipment for each bus in the relevant subsystem. 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 138 kV POI bus. The PSS/E “Automatic Sequence Fault Calculation (ASCC)” fault analysis module was used to calculate the fault current levels in the transmission system with and without GEN-2016-030 and GEN-2017-232 online. The existing SGF, GEN-2020-SR2 and GEN-2024-SR13, was left online for this analysis.

Aneden created a short circuit model using the 25SP DISIS-2021-001 stability study model by adjusting the GEN-2016-030 and GEN-2017-232 short circuit parameters consistent with the submitted data. The adjusted parameters used in the short circuit analysis are shown in Table 5-1 below. No other changes were made to the model.

Table 5-1: Short Circuit Model Parameters*

Parameter	Value by Generator Bus#	Value by Generator Bus#
	587203	760265
Machine MVA Base	114.4	57.2
R (pu)	0.0	0.0
X'' (pu)	0.642	0.642

*pu values based on Machine MVA Base

5.2 Results

The results of the short circuit analysis compared the 25SP model with GEN-2020-SR2 and GEN-2024-SR13 online and the GEN-2016-030 and GEN-2017-232 modifications not connected to the stability Scenario 2 dispatch model with both the existing SGFs and GEN-2016-030 and GEN-2017-232 in service as described in Section 6.1. The GEN-2016-030 and GEN-2017-232 POI bus (Brown 138 kV) fault current magnitudes for the comparison cases are provided in Table 5-2 showing a fault current of 9.82 kA with the GEN-2016-030 and GEN-2017-232 projects online. Table 5-3 shows the maximum fault current magnitudes and fault current increases with the GEN-2016-030 and GEN-2017-232 projects online.

The maximum fault current calculated within 5 buses of the POI was 19.8 kA for the 25SP model. The maximum GEN-2016-030 and GEN-2017-232 contribution to three-phase fault currents was about 9% and 0.81 kA.

Table 5-2: POI Short Circuit Comparison Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	kA Change	%Change
25SP	9.01	9.82	0.81	9.0%

Table 5-3: 25SP Short Circuit Comparison Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	5.9	0.01	0.1%
138	19.8	0.81	9.0%
345	11.5	0.08	0.7%
Max	19.8	0.81	9.0%

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the modifications to GEN-2016-030 and GEN-2017-232. The analysis was performed according to SPP's Disturbance Performance Requirements⁶. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix A. The existing base case issues and simulation plots can be found in Appendix C.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested GEN-2016-030 configuration of 26 x Sungrow SG4400 solar inverters operating at 3.9327 MW (REGCA1) and GEN-2017-232 configuration of 13 x Sungrow SG4400 solar inverters operating at 4.0925 MW (REGCA1). This stability analysis was performed using Siemens PTI's PSS/E version 34.8.1 software.

The modifications requested for the GEN-2016-030 and GEN-2017-232 projects were used to create modified stability models for this impact study based on the DISIS-2021-001 stability study models:

- 2025 Summer Peak (25SP),
- 2025 Winter Peak (25WP)

Aneden reviewed GIRs that shared the same POI, Brown 138 kV, and updated their models as applicable based on SPP's confirmation of the latest project configurations. The two modifications under study, GEN-2016-030 and GEN-2017-232, are the EGFs for the GEN-2020-SR2 and GEN-2024-SR13 SGF projects, respectively. As a result, Aneden included the accepted GEN-2020-SR2 and GEN-2024-SR13 surplus projects in the base models and created two stability scenarios to accommodate the status of both GEN-2020-SR2 and GEN-2024-SR13.

Two stability model scenarios were developed using these models to ensure all reliability conditions were studied. The first scenario (Scenario 1) was comprised of both GEN-2016-030 and GEN-2017-232 online at 100% of the assumed dispatch (102.25 MW and 53.2 MW) while the GEN-2020-SR2 and GEN-2024-SR13 generators were offline and disconnected.

The EGF/SGF dispatch combination for the second scenario (Scenario 2) was taken from the GEN-2020-SR2⁷ and GEN-2024-SR13⁸ reports. The study scenarios are shown in Table 6-1.

Table 6-1: Study Scenarios (Generator Dispatch MW)

Scenario	GEN-2016-030 (EGF) (MW)	GEN-2017-232 (EGF) (MW)	GEN-2020-SR2 (SGF) (MW)	GEN-2024-SR13 (SGF) (MW)	EGFs + SGFs (MW)
1	102.25	53.2	0 (offline)	0 (offline)	155.45
2	90	10.44	10	42.0315	152.4715

⁶ SPP Disturbance Performance Requirements:

[https://www.spp.org/documents/28859/spp%20disturbance%20performance%20requirements%20\(twg%20approved\).pdf](https://www.spp.org/documents/28859/spp%20disturbance%20performance%20requirements%20(twg%20approved).pdf)

⁷ GEN-2020-SR2 Surplus Service Impact Study - June 30, 2021

⁸ GEN-2024-SR13 Surplus Service Impact Study - October 15, 2024

The dynamic model data for the GEN-2016-030 and GEN-2017-232 projects is provided in Appendix A. The 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:

- The PSSE dynamic simulation iterations and acceleration factor were adjusted as needed to resolve PSSE dynamic simulation crashes.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2016-030 and GEN-2017-232 and other current and prior queued projects in Group 4. In addition, voltages of five (5) buses away from the POI of the GEN-2016-030 and GEN-2017-232 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 327 (EES-EAI), 330 (AECI), 351 (EES), 356 (AMMO), 502 (CLEC), 515 (SWPA), 520 (AEPW), 523 (GRDA), 524 (OKGE), 525 (WFEC), 526 (SPS), 527 (OMPA), 534 (SUNC), 536 (WERE), 544 (EMDE), and 546 (SPRM) were monitored. The voltages of all 100 kV and above buses within the study area were monitored as well.

6.2 Fault Definitions

Aneden developed fault events as required to study the modification. The new set of faults was 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 6-2 below. These contingencies were applied to the modified 25SP and 25WP models.

Table 6-2: Fault Definitions

Fault ID	Planning Event	Event Description
FLT1000-SB	P4	Stuck Breaker on BODLE 4 (515155) 138 kV Bus a. Apply single phase fault at the BODLE 4 (515155) 138 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip bus BODLE 4 (515155) 138 kV.
FLT1001-SB	P4	Stuck Breaker on CANEYCK4 (515150) 138 kV Bus a. Apply single phase fault at the CANEYCK4 (515150) 138 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the CANEYCK4 (515150) 138 kV to MADINDT4 (515149) 138 kV line CKT 1. b.2.Trip the STRRDTP4 (515944) 138 kV to BROWN 4 (515157) 138 kV line CKT 1. b.3.Trip the BROWNTP4 (515152) 138 kV to BODLE 4 (515155) 138 kV line CKT 1.
FLT1002-SB	P4	Stuck Breaker on CANEYCK4 (515150) 138 kV Bus a. Apply single phase fault at the CANEYCK4 (515150) 138 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the CANEYCK4 (515150) 138 kV to MADINDT4 (515149) 138 kV line CKT 1. b.2.Trip the CANEYCK4 (515150) 138 kV to JOHNCO 4 (514808) 138 kV line CKT 1.
FLT1003-SB	P4	Stuck Breaker on CANEYCK4 (515150) 138 kV Bus a. Apply single phase fault at the CANEYCK4 (515150) 138 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the CANEYCK4 (515150) 138 kV to JOHNCO 4 (514808) 138 kV line CKT 1. b.2.Trip the CANEYCK4 (515150) 138 kV to TEXOMAJ4 (521067) 138 kV line CKT 1.
FLT1004-SB	P4	Stuck Breaker on CANEYCK4 (515150) 138 kV Bus a. Apply single phase fault at the CANEYCK4 (515150) 138 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the CANEYCK4 (515150) 138 kV to TEXOMAJ4 (521067) 138 kV line CKT 1. b.2.Trip the STRRDTP4 (515944) 138 kV to BROWN 4 (515157) 138 kV line CKT 1. b.3.Trip the BROWNTP4 (515152) 138 kV to BODLE 4 (515155) 138 kV line CKT 1.

Table 6-2 Continued

Fault ID	Planning Event	Event Description
FLT1005-SB	P4	Stuck Breaker on S BROWN4 (505602) 138 kV Bus a. Apply single phase fault at the S BROWN4 (505602) 138 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1. Trip bus S BROWN4 (505602) 138 kV. Trip generator(s) on the Bus DEN #1 1 (505606) 13.8 kV Trip generator(s) on the Bus DEN #2 1 (505608) 13.8 kV
FLT1006-SB	P4	Stuck Breaker on BROWN 4 (515157) 138 kV Bus a. Apply single phase fault at the BROWN 4 (515157) 138 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1. Trip bus BROWN 4 (515157) 138 kV. b.2. Trip the LTLCTY4 (515151) 138 kV to CANEYCK4 (515150) 138 kV line CKT 1. b.3. Trip the BROWNTP4 (515152) 138 kV to BODLE 4 (515155) 138 kV line CKT 1. Trip generator(s) on the Bus G16-030-GEN1 (587203) 0.6 kV Trip generator(s) on the Bus G17-232-GEN1 (760265) 0.6 kV Trip generator(s) on the Bus G21-001-GEN1 (765302) 0.9 kV Trip generator(s) on the Bus G20-SR2-GEN (587206) 0.7 kV Trip generator(s) on the Bus G24-SR13-GEN (924131) 0.7 kV
FLT9000-3PH	P1	3 Phase fault on BROWN 4 (515157) 138 kV to GEN-2016-030 (587200) 138 kV line CKT 1, near BROWN 4 (515157) 138 kV. a. Apply fault at the BROWN 4 (515157) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. Trip generator(s) on the Bus G16-030-GEN1 (587203) 0.6 kV Trip generator(s) on the Bus G17-232-GEN1 (760265) 0.6 kV Trip generator(s) on the Bus G20-SR2-GEN (587206) 0.7 kV Trip generator(s) on the Bus G24-SR13-GEN (924131) 0.7 kV
FLT9001-3PH	P1	3 Phase fault on BROWN 4 (515157) 138 kV to GEN-2021-001 (765300) 138 kV line CKT 1, near BROWN 4 (515157) 138 kV. a. Apply fault at the BROWN 4 (515157) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. Trip generator(s) on the Bus G21-001-GEN1 (765302) 0.9 kV
FLT9002-3PH	P1	3 Phase fault on BROWN 4 (515157) 138 kV to STRRDTP4 (515944) 138 kV line CKT 1, near BROWN 4 (515157) 138 kV. a. Apply fault at the BROWN 4 (515157) 138 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.
FLT9003-3PH	P1	3 Phase fault on CANEYCK4 (515150) 138 kV to LTLCTY4 (515151) 138 kV line CKT 1, near CANEYCK4 (515150) 138 kV. a. Apply fault at the CANEYCK4 (515150) 138 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 CANEYCK4 (515150) 138 kV to MADINDT4 (515149) 138 kV line CKT 1, near CANEYCK4 (515150) 138 kV. a. Apply fault at the CANEYCK4 (515150) 138 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 MADINDT4 (515149) 138 kV to CANEYCK4 (515150) 138 kV line CKT 1, near MADINDT4 (515149) 138 kV. a. Apply fault at the MADINDT4 (515149) 138 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 MADINDT4 (515149) 138 kV to MADLIND4 (515158) 138 kV line CKT 1, near MADINDT4 (515149) 138 kV. a. Apply fault at the MADINDT4 (515149) 138 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 6-2 Continued

Fault ID	Planning Event	Event Description
FLT9007-3PH	P1	3 Phase fault on MADINDT4 (515149) 138 kV to GLASSES4 (515147) 138 kV line CKT 1, near MADINDT4 (515149) 138 kV. a. Apply fault at the MADINDT4 (515149) 138 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 CANEYCK4 (515150) 138 kV to TEXOMAJ4 (521067) 138 kV line CKT 1, near CANEYCK4 (515150) 138 kV. a. Apply fault at the CANEYCK4 (515150) 138 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.
FLT9009-3PH	P1	3 Phase fault on TEXOMAJ4 (521067) 138 kV to CANEYCK4 (515150) 138 kV line CKT 1, near TEXOMAJ4 (521067) 138 kV. a. Apply fault at the TEXOMAJ4 (521067) 138 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 TEXOMAJ4 (521067) 138 kV to ENOSJCT4 (520467) 138 kV line CKT 1, near TEXOMAJ4 (521067) 138 kV. a. Apply fault at the TEXOMAJ4 (521067) 138 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.
FLT9011-3PH	P1	3 Phase fault on TEXOMAJ4 (521067) 138 kV to LEBANTP4 (520972) 138 kV line CKT 1, near TEXOMAJ4 (521067) 138 kV. a. Apply fault at the TEXOMAJ4 (521067) 138 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.
FLT9012-3PH	P1	3 Phase fault on CANEYCK4 (515150) 138 kV to JOHNCO 4 (514808) 138 kV line CKT 1, near CANEYCK4 (515150) 138 kV. a. Apply fault at the CANEYCK4 (515150) 138 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.
FLT9013-3PH	P1	3 Phase fault on JOHNCO 4 (514808) 138 kV to CANEYCK4 (515150) 138 kV line CKT 1, near JOHNCO 4 (514808) 138 kV. a. Apply fault at the JOHNCO 4 (514808) 138 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.
FLT9014-3PH	P1	3 Phase fault on JOHNCO 4 (514808) 138 kV to RUSSET-4 (515120) 138 kV line CKT 1, near JOHNCO 4 (514808) 138 kV. a. Apply fault at the JOHNCO 4 (514808) 138 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.
FLT9015-3PH	P1	3 Phase fault on BODLE 4 (515155) 138 kV to BROWNT4 (515152) 138 kV line CKT 1, near BODLE 4 (515155) 138 kV. a. Apply fault at the BODLE 4 (515155) 138 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.
FLT9016-3PH	P1	3 Phase fault on BODLE 4 (515155) 138 kV to COLBRTP4 (515159) 138 kV line CKT 1, near BODLE 4 (515155) 138 kV. a. Apply fault at the BODLE 4 (515155) 138 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 6-2 Continued

Fault ID	Planning Event	Event Description
FLT9017-3PH	P1	3 Phase fault on COLBRTP4 (515159) 138 kV to BODLE 4 (515155) 138 kV line CKT 1, near COLBRTP4 (515159) 138 kV. a. Apply fault at the COLBRTP4 (515159) 138 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.
FLT9018-3PH	P1	3 Phase fault on BROWN 4 (515157) 138 kV to S BROWN4 (505602) 138 kV line CKT 2, near BROWN 4 (515157) 138 kV. a. Apply fault at the BROWN 4 (515157) 138 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 S BROWN4 (505602) 138 kV to BROWN 4 (515157) 138 kV line CKT 2, near S BROWN4 (505602) 138 kV. a. Apply fault at the S BROWN4 (505602) 138 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.
FLT9020-3PH	P1	3 Phase fault on S BROWN4 (505602) 138 kV to COLBRTP4 (515159) 138 kV line CKT 1, near S BROWN4 (505602) 138 kV. a. Apply fault at the S BROWN4 (505602) 138 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.
FLT9021-3PH	P1	3 Phase fault on COLBRTP4 (515159) 138 kV to S BROWN4 (505602) 138 kV line CKT 1, near COLBRTP4 (515159) 138 kV. a. Apply fault at the COLBRTP4 (515159) 138 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.
FLT9022-3PH	P1	3 Phase fault on COLBRTP4 (515159) 138 kV to BUTRFLD4 (515176) 138 kV line CKT 1, near COLBRTP4 (515159) 138 kV. a. Apply fault at the COLBRTP4 (515159) 138 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.
FLT9023-3PH	P1	3 Phase fault on S BROWN4 (505602) 138 kV to RUSSETT4 (521044) 138 kV line CKT 1, near S BROWN4 (505602) 138 kV. a. Apply fault at the S BROWN4 (505602) 138 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.
FLT9024-3PH	P1	3 Phase fault on RUSSETT4 (521044) 138 kV to S BROWN4 (505602) 138 kV line CKT 1, near RUSSETT4 (521044) 138 kV. a. Apply fault at the RUSSETT4 (521044) 138 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 RUSSETT4 (521044) 138 kV to RUSSET-4 (515120) 138 kV line CKT 1, near RUSSETT4 (521044) 138 kV. a. Apply fault at the RUSSETT4 (521044) 138 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.
FLT9026-3PH	P1	3 Phase fault on S BROWN4 (505602) 138 kV to SCLMNJC4 (521049) 138 kV line CKT 1, near S BROWN4 (505602) 138 kV. a. Apply fault at the S BROWN4 (505602) 138 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 6-2 Continued

Fault ID	Planning Event	Event Description
FLT9027-3PH	P1	3 Phase fault on SCLMNJC4 (521049) 138 kV to S BROWN4 (505602) 138 kV line CKT 1, near SCLMNJC4 (521049) 138 kV. a. Apply fault at the SCLMNJC4 (521049) 138 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 SCLMNJC4 (521049) 138 kV to SCOLEMN4 (520463) 138 kV line CKT 1, near SCLMNJC4 (521049) 138 kV. a. Apply fault at the SCLMNJC4 (521049) 138 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 SCLMNJC4 (521049) 138 kV to DURANTP4 (520884) 138 kV line CKT 1, near SCLMNJC4 (521049) 138 kV. a. Apply fault at the SCLMNJC4 (521049) 138 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 S BROWN4 (505602) 138 kV to KIERSEY4 (520963) 138 kV line CKT 1, near S BROWN4 (505602) 138 kV. a. Apply fault at the S BROWN4 (505602) 138 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.
FLT9031-3PH	P1	3 Phase fault on KIERSEY4 (520963) 138 kV to S BROWN4 (505602) 138 kV line CKT 1, near KIERSEY4 (520963) 138 kV. a. Apply fault at the KIERSEY4 (520963) 138 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.
FLT9032-3PH	P1	3 Phase fault on KIERSEY4 (520963) 138 kV to COLBERT4 (520860) 138 kV line CKT 1, near KIERSEY4 (520963) 138 kV. a. Apply fault at the KIERSEY4 (520963) 138 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.
FLT9033-3PH	P1	3 Phase fault on S BROWN4 (505602) 138 kV to TUPELO 4 (505600) 138 kV line CKT 1, near S BROWN4 (505602) 138 kV. a. Apply fault at the S BROWN4 (505602) 138 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.
FLT9034-3PH	P1	3 Phase fault on TUPELO 4 (505600) 138 kV to S BROWN4 (505602) 138 kV line CKT 1, near TUPELO 4 (505600) 138 kV. a. Apply fault at the TUPELO 4 (505600) 138 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.
FLT9035-3PH	P1	3 Phase fault on TUPELO 4 (505600) 138 kV to BOGGY4 (521074) 138 kV line CKT 1, near TUPELO 4 (505600) 138 kV. a. Apply fault at the TUPELO 4 (505600) 138 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.
FLT9036-3PH	P1	3 Phase fault on TUPELO 4 (505600) 138 kV to ALLENGT4 (510881) 138 kV line CKT 1, near TUPELO 4 (505600) 138 kV. a. Apply fault at the TUPELO 4 (505600) 138 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 6-2 Continued

Fault ID	Planning Event	Event Description
FLT9037-3PH	P1	3 Phase fault on TUPELO 4 (505600) 138 kV to CENTRATAP4 (505665) 138 kV line CKT 1, near TUPELO 4 (505600) 138 kV. a. Apply fault at the TUPELO 4 (505600) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. Trip generator(s) on the Bus CENTRAHOMA1 (505668) 13.2 kV Trip generator(s) on the Bus CENTRAHOM_1 (505670) 13.2 kV 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.
FLT9038-3PH	P1	3 Phase fault on TUPELO 4 (505600) 138 kV to ALLEN 4 (505598) 138 kV line CKT 1, near TUPELO 4 (505600) 138 kV. a. Apply fault at the TUPELO 4 (505600) 138 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.
FLT9039-3PH	P1	3 Phase fault on TUPELO 4 (505600) 138 kV to STNWLSW4 (521071) 138 kV line CKT 1, near TUPELO 4 (505600) 138 kV. a. Apply fault at the TUPELO 4 (505600) 138 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.
FLT9040-3PH	P1	3 Phase fault on TUPELO 4 (505600) 138 kV to TUPELO 4 (520406) 138 kV line CKT 1, near TUPELO 4 (505600) 138 kV. a. Apply fault at the TUPELO 4 (505600) 138 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.

6.3 Scenario 1 Results

Table 6-3 shows the relevant results of the fault events simulated for each of the modified models in Scenario 1. Existing DISIS base case issues are documented separately in Appendix C. The associated stability plots are also provided in Appendix C.

Table 6-3: Scenario 1 Dynamic Stability Results (GEN-2016-030 = 102.25, GEN-2017-232 = 53.2, GEN-2020-SR2 and GEN-2024-SR13 = 0)

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT1000-SB	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
FLT9000-3PH	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

Table 6-3 continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable
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
FLT9032-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9033-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9034-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9035-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9036-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9037-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9038-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9039-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9040-3PH	Pass	Pass	Stable	Pass	Pass	Stable

The results of the Scenario 1 dynamic stability showed several existing base case issues that were found in both the original DISIS-2021-001 models (without GEN-2020-SR2 and GEN-2024-SR13) and in the models with the GEN-2016-030 and GEN-2017-232 modifications (and GEN-2020-SR2 and GEN-2024-SR13) included. These issues were not attributed to the GEN-2016-030 and GEN-2017-232 modification requests and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2016-030 and GEN-2017-232 modification requests observed during the simulated faults. Additionally, the projects were 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.

6.4 Scenario 2 Results

Table 6-4 shows the relevant results of the fault events simulated for each of the modified models in Scenario 2. Existing DISIS base case issues are documented separately in Appendix C. The associated stability plots are also provided in Appendix C.

Table 6-4: Scenario 2 Dynamic Stability Results (GEN-2016-030 = 90, GEN-2017-232 = 10.44, GEN-2020-SR2 = 10, and GEN-2024-SR13 = 42.0315)

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT1000-SB	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
FLT9000-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-4 continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable
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
FLT9032-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9033-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9034-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9035-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9036-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9037-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9038-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9039-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9040-3PH	Pass	Pass	Stable	Pass	Pass	Stable

The results of the Scenario 2 dynamic stability showed several existing base case issues that were found in both the original DISIS-2021-001 models (without GEN-2020-SR2 and GEN-2024-SR13) and in the models with the GEN-2016-030 and GEN-2017-232 modifications (and GEN-2020-SR2 and GEN-2024-SR13) included. These issues were not attributed to the GEN-2016-030 and GEN-2017-232 modification requests and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2016-030 and GEN-2017-232 modification requests observed during the simulated faults. Additionally, the projects were 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.

The modified generating capacities of both GEN-2016-030 and GEN-2017-232 exceed the GIA Interconnection Service amounts, 100 MW and 52.2 MW respectively, as listed in Appendix A of each 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 both GIAs.

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 modifications on the prior study results. Aneden determined that the requested modifications did not negatively impact the prior study dynamic stability and short circuit results, and the modifications to the projects were not significant enough to change the previously studied steady-state conclusions.

This determination implies that any network upgrades already required by GEN-2016-030 and GEN-2017-232 would not be negatively impacted and that no new upgrades are required due to the requested modifications, thus not resulting in a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.