Report on

GEN-2017-033 Modification Request Impact Study

Revision R1 July 13, 2023

Submitted to
Southwest Power Pool

anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
7/13/2023	Aneden Consulting	Initial Report Issued

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2017-033, an active Generation Interconnection Request (GIR) with a Point of Interconnection (POI) at the Oklaunion 345 kV Substation.

The GEN-2017-033 wind project interconnects in the American Electric Power (AEP) control area with a capacity of 200 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2017-033 to change the turbine configuration to 59 x GE 3.4 MW for a total capacity of 200.6 MW. This generating capability for GEN-2017-033 (200.6 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 200 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

In addition, the modification request included changes to the generation interconnection line, collection system, generator step-up transformers, and main substation transformers. The existing and modified configurations for GEN-2017-033 are shown in Table ES-2.

Table ES-1: GEN-2017-033 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2017-033	Oklaunion 345 kV (511456)	80 x GE 2.5 MW = 200 MW	200

Table ES-2: GEN-2017-033 Modification Request

<table>
<tr><th>Facility</th><th colspan="2">Existing Configuration</th><th colspan="2">Modification Configuration</th></tr>
<tr><td>Point of Interconnection</td><td colspan="2">Oklaunion 345 kV (511456)</td><td colspan="2">Oklaunion 345 kV (511456)</td></tr>
<tr><td>Configuration/Capacity</td><td colspan="2">80 x GE 2.5 MW = 200 MW</td><td colspan="2">59 x GE 3.4 MW = 200.6 MW [dispatch]
POI limited to 200 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td colspan="2">Length = 26 miles
R = 0.001129 pu
X = 0.012994 pu
B = 0.115576 pu
Rating MVA = 0 MVA</td><td colspan="2">Length = 29 miles
R = 0.001245 pu
X = 0.013900 pu
B = 0.257632 pu
Rating MVA = 1363 MVA</td></tr>
<tr><td>Main Substation Transformer[1]</td><td>X = 8.997%,
R = 0.225%,
Winding MVA = 80 MVA,
Rating MVA = 133 MVA</td><td>X = 8.997%,
R = 0.225%,
Winding MVA = 80 MVA,
Rating MVA = 133 MVA</td><td>X = 8.996%,
R = 0.261%,
Winding MVA = 80 MVA,
Rating MVA = 134 MVA</td><td>X = 8.996%,
R = 0.261%,
Winding MVA = 80 MVA,
Rating MVA = 134 MVA</td></tr>
<tr><td>Equivalent GSU Transformer[1]</td><td>Gen 1 Equivalent Qty: 40
X = 5.699%,
R = 0.759%,
Winding MVA = 120 MVA,
Rating MVA = 120 MVA</td><td>Gen 1 Equivalent Qty: 40
X = 5.699%,
R = 0.759%,
Winding MVA = 120 MVA,
Rating MVA = 120 MVA</td><td>Gen 1 Equivalent Qty: 30
X = 7.484%,
R = 0.998%,
Winding MVA = 114.33 MVA,
Rating MVA[2] = 114.3 MVA</td><td>Gen 1 Equivalent Qty: 29
X = 7.484%,
R = 0.998%,
Winding MVA = 110.519 MVA,
Rating MVA[2] = 110.5 MVA</td></tr>
<tr><td>Equivalent Collector Line[3]</td><td>R = 0.005468 pu
X = 0.006700 pu
B = 0.030351 pu</td><td>R = 0.006572 pu
X = 0.008510 pu
B = 0.037731 pu</td><td>R = 0.005239 pu
X = 0.005976 pu
B = 0.027842 pu</td><td>R = 0.006024 pu
X = 0.007125 pu
B = 0.031871 pu</td></tr>
<tr><td>Generator Dynamic Model[4]
& Power Factor</td><td>40 x GE 2.5 MW
(GEWTGCU1)[4]
Leading: 0.99
Lagging: 0.99</td><td>40 x GE 2.5 MW
(GEWTGCU1)[4]
Leading: 0.99
Lagging: 0.99</td><td>30 x GE 3.4 MW (REGCA1)[4]
Leading: 0.9
Lagging: 0.9</td><td>29 x GE 3.4 MW (REGCA1)[4]
Leading: 0.9
Lagging: 0.9</td></tr>
</table>

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

SPP determined that 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 while the modification used the same turbine manufacturer, GE, the change in stability model from GEWTGCU1to REGCA1 required short circuit and dynamic stability analyses.

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

Aneden performed the analyses using the modification request data based on the DISIS-2017-002-1 study models:

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

All analyses were performed using the Siemens PTI PSS/E[1] version 34 software and the results are summarized below.

The results of the reactive power analysis using the 25SP model showed that the GEN-2017-033 project needed 32.1 MVAr of shunt reactors on the 34.5 kV bus of the project substations with the modifications in place, an increase from the 9.8 MVAr found in the DISIS-2017-001 study[2]. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind 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 GEN-2017-033 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2017-033 POI was no greater than 0.83 kA. The maximum three-phase fault current level within 5 buses of the POI with the GEN-2017-033 generators online were below 36 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. 34 events were simulated, which included three-phase faults and single-line-to-ground stuck breaker faults.

The results of the dynamic stability analysis showed several existing base case issues that were found in both the original DISIS-2017-002-1 model and in the model with GEN-2017-033 included. These issues were not attributed to the GEN-2017-033 modification request and are detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2017-033 modification request observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

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

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

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

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

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

1.0 Scope of Study

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2017-033. 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 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.

1.2 Stability Analysis, Short Circuit Analysis

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

1.3 Reactive Power Analysis

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

1.4 Study Limitations

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

2.0 Project and Modification Request

The GEN-2017-033 Interconnection Customer has requested a modification to its Generation Interconnection Request (GIR) with a Point of Interconnection (POI) at the Oklaunion 345 kV Substation.

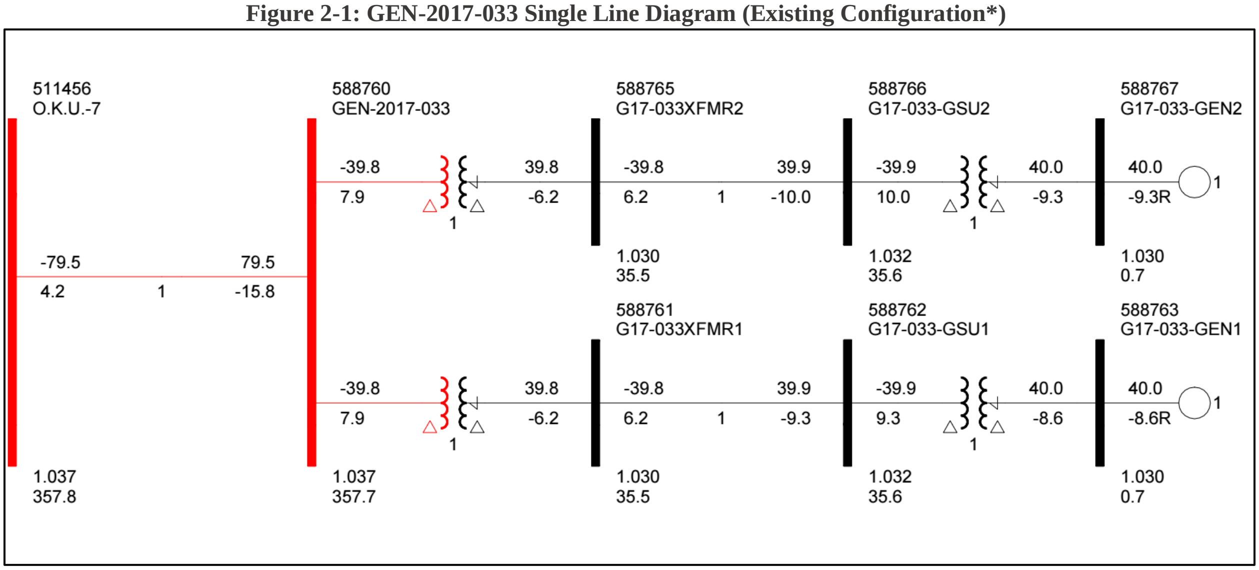
At the time of report posting, GEN-2017-033 is an active Interconnection Request with a queue status of "IA FULLY EXECUTED/ON SCHEDULE." GEN-2017-033 is a wind farm with a maximum summer and winter queue capacity of 200 MW with Energy Resource Interconnection Service (ERIS).

The GEN-2017-033 project is currently in the DISIS-2017-001 cluster. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2017-033 configuration using the DISIS-2017-002-1 stability models. The GEN-2017-033 project interconnects in the American Power Electric (AEP) control area with a capacity of 200 MW as shown in Table 2-1 below.

Table 2-1: GEN-2017-033 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2017-033	Oklaunion 345 kV (511456)	80 x GE 2.5 MW = 200 MW	200

Figure 2-1: GEN-2017-033 Single Line Diagram (Existing Configuration*)



*based on the DISIS-2017-002-1 25SP stability models

This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2017-033 to a turbine configuration of 59 x GE 3.4 MW for a total capacity of 200.6 MW. This generating capability for GEN-2017-033 (200.6 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 200 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

In addition, the modification request included changes to the generation interconnection line, collection system, generator step-up transformers, and main substation transformers. Figure 2-2 shows the power flow model single line diagram for the GEN-2017-033 modification. The existing and modified configurations for GEN-2017-033 are shown in Table 2-2.

Figure 2-2: GEN-2017-033 Single Line Diagram (Modification Configuration)

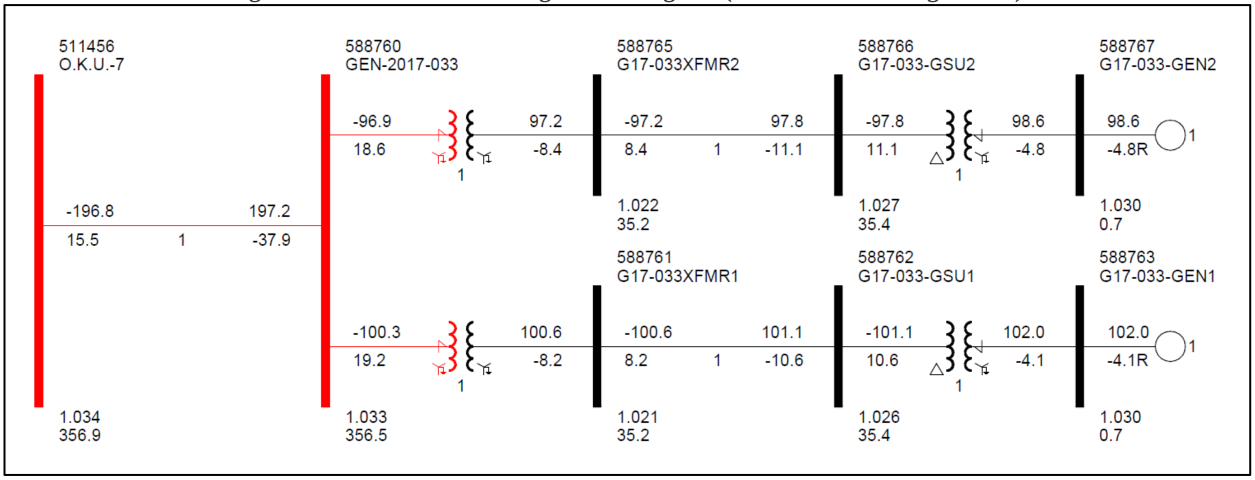


Table 2-2: GEN-2017-033 Modification Request

Facility	Existing Configuration		Modification Configuration	
Point of Interconnection	Oklaunion 345 kV (511456)		Oklaunion 345 kV (511456)	
Configuration/Capacity	80 x GE 2.5 MW = 200 MW		59 x GE 3.4 MW = 200.6 MW [dispatch] POI limited to 200 MW	
Generation Interconnection Line	Length = 26 miles R = 0.001129 pu X = 0.012994 pu B = 0.115576 pu Rating MVA = 0 MVA		Length = 29 miles R = 0.001245 pu X = 0.013900 pu B = 0.257632 pu Rating MVA = 1363 MVA	
Main Substation Transformer[1]	X = 8.997%, R = 0.225%, Winding MVA = 80 MVA, Rating MVA = 133 MVA	X = 8.997%, R = 0.225%, Winding MVA = 80 MVA, Rating MVA = 133 MVA	X = 8.996%, R = 0.261%, Winding MVA = 80 MVA, Rating MVA = 134 MVA	X = 8.996%, R = 0.261%, Winding MVA = 80 MVA, Rating MVA = 134 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 40 X = 5.699%, R = 0.759%, Winding MVA = 120 MVA, Rating MVA = 120 MVA	Gen 1 Equivalent Qty: 40 X = 5.699%, R = 0.759%, Winding MVA = 120 MVA, Rating MVA = 120 MVA	Gen 1 Equivalent Qty: 30 X = 7.484%, R = 0.998%, Winding MVA = 114.33 MVA, Rating MVA[2] = 114.3 MVA	Gen 1 Equivalent Qty: 29 X = 7.484%, R = 0.998%, Winding MVA = 110.519 MVA, Rating MVA[2] = 110.5 MVA
Equivalent Collector Line[3]	R = 0.005468 pu X = 0.006700 pu B = 0.030351 pu	R = 0.006572 pu X = 0.008510 pu B = 0.037731 pu	R = 0.005239 pu X = 0.005976 pu B = 0.027842 pu	R = 0.006024 pu X = 0.007125 pu B = 0.031871 pu
Generator Dynamic Model[4] & Power Factor	40 x GE 2.5 MW (GEWTGCU1)[4] Leading: 0.99 Lagging: 0.99	40 x GE 2.5 MW (GEWTGCU1)[4] Leading: 0.99 Lagging: 0.99	30 x GE 3.4 MW (REGCA1)[4] Leading: 0.9 Lagging: 0.9	29 x GE 3.4 MW (REGCA1)[4] Leading: 0.9 Lagging: 0.9

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

3.0 Existing vs Modification Comparison

To determine which analyses are required for the Study, the differences between the existing configuration and the requested modification were evaluated. Aneden performed this comparison and the resulting analyses using a set of modified study models developed based on the modification request data and the DISIS-2017-002-1 study models. The analysis was completed using PSS/E version 34 software.

The methodology and results of the comparisons are described below.

3.1 Turbine Parameters Comparison

SPP determined that while the modification used the same turbine manufacturer, GE, the change in stability model from GEWTGCU1to REGCA1 required short circuit and dynamic stability analysis. This is because the short circuit contribution and stability responses of the existing configuration and the requested modification's configuration may differ. The generator dynamic model for the modification can be found in Appendix A.

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

3.2 Equivalent Impedance Comparison Calculation

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

4.0 Reactive Power Analysis

The reactive power analysis was performed for GEN-2017-033 to determine the capacitive charging effects during reduced generation conditions (unsuitable wind speeds, unsuitable solar irradiance, insufficient state of charge, idle conditions, curtailment, etc.) at the generation site and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

4.1 Methodology and Criteria

The GEN-2017-033 generators were switched out of service while other system elements remained in-service. Shunt reactors were tested at the project's collection substation 34.5 kV buses to set the MVAr flow into the POI to approximately zero. The size of the shunt reactors 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-2017-002-1 stability study model.

4.2 Results

The results from the analysis showed that the GEN-2017-033 project needed approximately 32.1 MVAr of compensation at its project substations to reduce the POI MVAr to zero. This is an increase from the 9.8 MVAr found in the DISIS-2017-001 study[3]. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the updated topology. The final shunt reactor requirements for GEN-2017-033 are shown in Table 4-1.

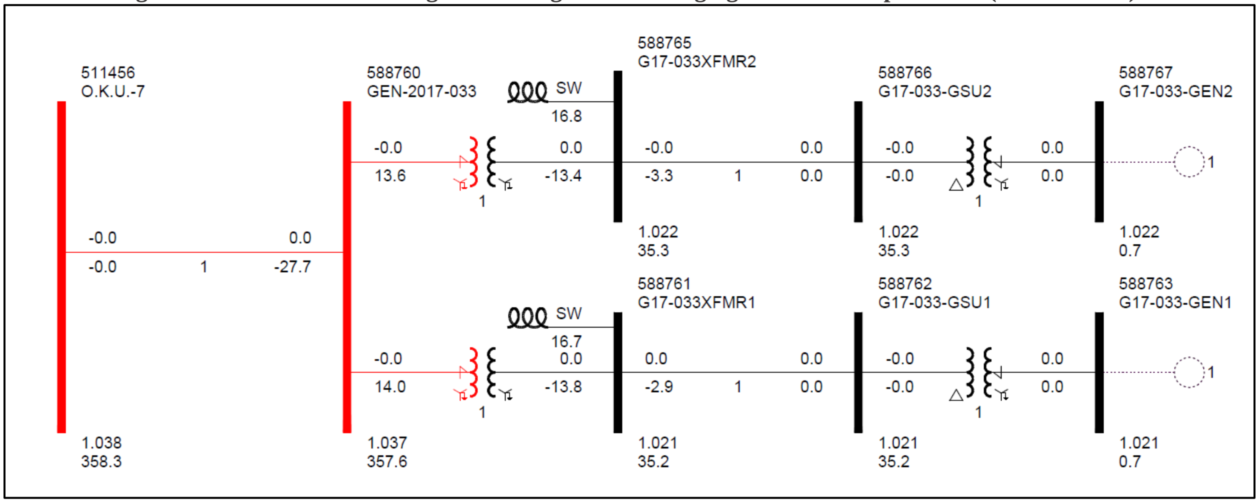
The information gathered from the reactive power analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator (TOP). The applicable reactive power requirements will be further reviewed by the TO and/or TOP.

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

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)
			25SP
GEN-2017-033	511456	O.K.U.-7	32.1

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

Figure 4-1: GEN-2017-033 Single Line Diagram w/ Charging Current Compensation (Modification)



5.0 Short Circuit Analysis

A short circuit study was performed using the 25SP model for GEN-2017-033. The detailed results of the short circuit analysis are provided in Appendix B.

5.1 Methodology

The short circuit analysis included applying a three-phase fault on buses up to 5 levels away from the 345 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels in the transmission system with and without GEN-2017-033 online.

Aneden created a short circuit model using the 25SP DISIS-2017-002-1 stability study model by adjusting the GEN-2017-033 short circuit parameters consistent with the modification 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#
	588767	588763
Machine MVA Base	103.76	107.34
R (pu)	0.0	0.0
X'' (pu)	0.2	0.2

*pu values based on Machine MVA Base

5.2 Results

The results of the short circuit analysis for the 25SP model are summarized in Table 5-2 and Table 5-3. The GEN-2017-033 POI bus (Oklaunion 345 kV - 511456) fault current magnitudes are provided in Table 5-2 showing a fault current of 5.93 kA with the GEN-2017-033 project online. Table 5-3 shows the maximum fault current magnitudes and fault current increases with the GEN-2017-033 project online.

The maximum fault current calculated within 5 buses of the GEN-2017-033 POI (including the POI bus) was less than 36 kA for the 25SP model. The maximum GEN-2017-033 contribution to three-phase fault current was about 16.3% and 0.83 kA.

Table 5-2: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	kA Change	%Change
25SP	5.10	5.93	0.83	16.3%

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Table 5-3: 25SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	16.4	0.06	0.4%
115	19.6	0.02	0.1%
138	35.4	0.32	1.4%
230	27.4	0.09	0.4%
345	32.7	0.83	16.3%
Max	**35.4**	**0.83**	**16.3%**

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine configuration change and other modifications to GEN-2017-033. The analysis was performed according to SPP's Disturbance Performance Requirements[4]. 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-2017-033 configuration of 59 x GE 3.4 MW (REGCA1). This stability analysis was performed using PTI's PSS/E version 34.8.0 software.

The modifications requested for the GEN-2017-033 project were used to create modified stability model**s** for this impact study based on the DISIS-2017-002-1 stability study models:

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

The modified dynamic model data for the GEN-2017-033 project is provided in Appendix A. The modified power flow models and associated dynamic database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data.

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

- The voltage protective relays at buses 761447, 761442, 761445, 761449, 589383, 573510, 760979, 760958, & 760937 were disabled to avoid generator tripping due to an instantaneous over voltage spike after fault clearing.
- The fault simulation file acceleration factor was reduced as needed to resolve stability simulation crashes.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2017-033 and other current and prior queued projects in their cluster group[5]. In addition, voltages of five (5) buses away from the POI of GEN-2017-033 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 520 (AEPW), 524 (OKGE), 526 (SPS), and 652 (WAPA) were monitored. The voltages of all 100 kV and above buses within the study area were monitored as well.

6.2 Fault Definitions

Aneden simulated the faults previously used for GEN-2017-033 and developed additional fault events as required. 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

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

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

0.6 pu. The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 25SP and 25WP models.

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT9001-3PH	P1	3 phase fault on the O.K.U.-7 (511456) to G17-151TAP (762216) 345 kV line CKT 1, near O.K.U.-7. a. Apply fault at the O.K.U.-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.
FLT9002-3PH	P1	3 phase fault on the O.K.U.-7 (511456) to L.E.S.-7 (511468) 345 kV line CKT 1, near O.K.U.-7. a. Apply fault at the O.K.U.-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.
FLT9003-3PH	P1	3 phase fault on the O.K.U.-7 (511456) to OKLAUN HVDC7 (511565) 345 kV line CKT 1, near O.K.U.-7. a. Apply fault at the O.K.U.-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.
FLT9004-3PH	P1	3 phase fault on the L.E.S.-7 (511468) to G17-171-TAP (760938) 345 kV line CKT 1, near L.E.S.-7. a. Apply fault at the L.E.S.-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.
FLT9005-3PH	P1	3 phase fault on the L.E.S.-7 (511468) to G16-091-TAP (587744) 345 kV line CKT 1, near L.E.S.-7. a. Apply fault at the L.E.S.-7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9006-3PH	P1	3 phase fault on the G17-171-TAP (760938) to TERRYRD7 (511568) 345 kV line CKT 1, near G17-171-TAP. a. Apply fault at the G17-171-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	3 phase fault on the LES 4 345 kV (511468)/ 138 kV (511467) /13.8 kV (511414) XFMR CKT 1, near L.E.S. -4 345 kV. a. Apply fault at the L.E.S. -4 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9008-3PH	P1	3 phase fault on the G17-171-TAP (760938) to GEN-2017-171 (760939) 345 kV line CKT 1, near G17-171-TAP. a. Apply fault at the G17-171-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip Generators G17-173GEN1 (760979), G17-172GEN1 (760958), G17-171GEN1 (760937).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9009-3PH	P1	3 phase fault on the G16-091-TAP (587744) to GEN-2016-095 (587770) 345 kV line CKT 1, near G16-091-TAP. a. Apply fault at the G16-091-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip Generators G16-095GEN1 (587773).** 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.
FLT9010-3PH	P1	3 phase fault on the G16-091-TAP (587744) to GRACMNT7 (515800) 345 kV line CKT 1, near G16-091-TAP. a. Apply fault at the G16-091-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.
FLT9011-3PH	P1	3 phase fault on the G16-091-TAP (587744) to GEN-2016-091 (587740) 345 kV line CKT 1, near G16-091-TAP. a. Apply fault at the G16-091-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generators G16-091-GEN1 (587743), G16-091-GEN2 (587749), G16-091-GEN3 (587747), G16-091-GEN4 (587748).** 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.
FLT9012-3PH	P1	3 phase fault on the G17-151TAP (762216) to TUCO_INT 7 (525832) 345 kV line CKT 1, near G17-151TAP. a. Apply fault at the G17-151TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9013-3PH	P1	3 phase fault on the G17-151TAP (762216) to GEN-2017-151 (762217) 345 kV line CKT 1, near G17-151TAP. a. Apply fault at the G17-151TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generators G17-151GEN1 (762220),G17-151GEN2 (762223),G17-151GEN3 (762226),G17-151GEN4 (762229)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9014-3PH	P1	3 phase fault on the TUCO_INT 7 (525832) to ELK_CT1 (525850) 345 kV line CKT 1, near TUCO_INT 7. a. Apply fault at the TUCO_INT 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generators ELK 1 (525844)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9015-3PH	P1	3 phase fault on the TUCO_INT 7 (525832) to BORDER (515458) 345 kV line CKT 1, near TUCO_INT 7. a. Apply fault at the TUCO_INT 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.
FLT9016-3PH	P1	3 phase fault on the TUCO_INT 7 (525832) to YOAKUM (526936) 345 kV line CKT 1, near TUCO_INT 7. a. Apply fault at the TUCO_INT 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.
FLT9017-3PH	P1	3 phase fault on the TUCO _INT 7 345 kV (525832)/ 230 kV (525830) /13.2 kV (525824) XFMR CKT 1, near TUCO_INT 7 (525832) 345 kV. a. Apply fault at the TUCO_INT 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9018-3PH	P1	3 phase fault on the TUCO _INT 7 345 kV (525832)/18 kV (525845) XFMR CKT 1, near TUCO_INT 7 (525832) 345 kV. a. Apply fault at the TUCO_INT 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer. **Trip generators ELK 2 (525845)**

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9019-3PH	P1	3 phase fault on the TUCO_INT 6 (525830) to SWISHER 6 (525213) 230 kV line CKT 1, near TUCO_INT 6. a. Apply fault at the TUCO_INT 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9020-3PH	P1	3 phase fault on the TUCO_INT 6 (525830) to ANTELOPE_1 6 (525840) 230 kV line CKT 1, near TUCO_INT 6. a. Apply fault at the TUCO_INT 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. **Trip generator ANTELOPE A (525841), ANTELOPE B (525842), ANTELOPE C (525843).** 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 the TUCO_INT 6 (525830) to JONES 6 (526337) 230 kV line CKT 1, near TUCO_INT 6. a. Apply fault at the TUCO_INT 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9022-3PH	P1	3 phase fault on the TUCO_INT 6 (525830) to TOLK 6 (525531) 230 kV line CKT 1, near TUCO_INT 6. a. Apply fault at the TUCO_INT 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9023-3PH	P1	3 phase fault on the TUCO_INT 6 (525830) to CARLISLE 6 (526161) 230 kV line CKT 1, near TUCO_INT 6. a. Apply fault at the TUCO_INT 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9024-3PH	P1	3 phase fault on the TUCO_INT 6 (525830) to HALE_WNDCL16 (525957) 230 kV line CKT 1, near TUCO_INT 6. a. Apply fault at the TUCO_INT 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. **Trip Generators HALE 1,2 and 3 (525951, 525952, and 525953)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9025-3PH	P1	3 phase fault on the TUCO_INT 6 230 kV (525830)/13 kV (525820) XFMR CKT 1, near TUCO_INT 6 (525830) 230 kV. a. Apply fault at the TUCO_INT 6 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer. **Trip generators TUCO_SVC 1 (525820)**
FLT9026-3PH	P1	3 phase fault on the GE M102345 230 kV (525830)/ 115 kV (525828) /13.2 kV (525821 XFMR CKT 1, near TUCO_INT 6 (525830) 230 kV. a. Apply fault at the TUCO_INT 6 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT1001-SB	P4	Stuck Breaker on TUCO_INT 7 (525832) 345kV bus. a. Apply single-phase fault at TUCO_INT 7 (525832) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the TUCO_INT 7 (525832) to BORDER (515458) 345 kV line CKT 1. d. Trip the TUCO_INT 7 (525832) to YOAKUM (526936) 345 kV line CKT 1.
FLT1002-SB	P4	Stuck Breaker on TUCO_INT 7 (525832) 345kV bus. a. Apply single-phase fault at TUCO_INT 7 (525832) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the TUCO_INT 7 (525832) to G17-151TAP (762216) 345 kV line CKT 1. d. Trip the TUCO_INT 7 (525832) to YOAKUM (526936) 345 kV line CKT 1.
FLT1003-SB	P4	Stuck Breaker on TUCO_INT 7 (525832) 345kV bus. a. Apply single-phase fault at TUCO_INT 7 (525832) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the TUCO_INT 7 (525832) to YOAKUM (526936) 345 kV line CKT 1. d. Trip the TUCO_INT 7 (525832) to ELK_CT1 (525850) 345 kV line CKT 1. e. Trip the TUCO _INT 7 345 kV (525832)/18 kV (525845) XFMR CKT 1. Trip generators ELK 1 (525844) and ELK 2 (525845).

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1004-SB	P4	Stuck Breaker on TUCO_INT 7 (525832) 345kV bus. a. Apply single-phase fault at TUCO_INT 7 (525832) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the TUCO_INT 7 (525832) to BORDER (515458) 345 kV line CKT 1. d. Trip the TUCO_INT 7 345 kV (525832)/ 230 kV (525830) /13.2 kV (525824) XFMR CKT 1.
FLT1005-SB	P4	Stuck Breaker on TUCO_INT 7 (525832) 345kV bus. a. Apply single-phase fault at TUCO_INT 7 (525832) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the TUCO_INT 7 (525832) to G17-151TAP (762216) 345 kV line CKT 1. d. Trip the TUCO_INT 7 345 kV (525832)/ 230 kV (525830) /13.2 kV (525825) XFMR CKT 2.
FLT1006-SB	P4	Stuck Breaker on L.E.S.-7 (511468) 345kV bus. a. Apply single-phase fault at L.E.S.-7 (511468) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the L.E.S.-7 (511468) to G16-091-TAP (587744) 345 kV line CKT 1. d. Trip the LES 4 345 kV (511468)/ 138 kV (511467) /13.8 kV (511414) XFMR CKT 1.
FLT1007-SB	P4	Stuck Breaker on L.E.S.-7 (511468) 345kV bus. a. Apply single-phase fault at L.E.S.-7 (511468) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the L.E.S.-7 (511468) to G17-171-TAP (760938) 345 kV line CKT 1. d. Trip the L.E.S.-7 (511468) to O.K.U.-7 (511456) 345 kV line CKT 1.
FLT1008-SB	P4	Stuck Breaker on L.E.S.-7 (511468) 345kV bus. a. Apply single-phase fault at L.E.S.-7 (511468) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the L.E.S.-7 (511468) to O.K.U.-7 (511456) 345 kV line CKT 1. d. Trip the L.E.S.-4 345 kV (511468)/ 138 kV (511467) /13.8 kV (511414) XFMR CKT 1.

6.3 Results

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

Table 6-2: GEN-2017-033 Dynamic Stability Results

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage 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
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	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
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable

The results of the dynamic stability analysis showed several existing base case issues that were found in both the original DISIS-2017-002-1 model and the model with the GEN-2017-033 modification included. These issues were not attributed to the GEN-2017-033 modification request and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2017-033 modification request observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

7.0 Modified Capacity Exceeds GIA Capacity

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

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

The modified generating capacity of GEN-2017-033 (200.6 MW) exceeds the GIA Interconnection Service amount, 200 MW, as listed in Appendix A of the GIA.

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

8.0 Material Modification Determination

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

8.1 Results

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

This determination implies that any network upgrades already required by GEN-2017-033 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.