Submitted to
Southwest Power Pool

SPP Southwest Power Pool

Report On

GEN-2016-003
Modification Request Impact Study

Revision R1

Date of Submittal
March 10, 2021

anedenconsulting.com

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDICES

Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
03/10/2021	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-2016-003, an active generation Interconnection Request with a point of interconnection (POI) at the G16-003-TAP 345 kV bus on the Badger to Woodward 345 kV double circuit.

The GEN-2016-003 project is proposed to interconnect in the Oklahoma Gas & Electric (OKGE) control area with a generating capacity of 248.4 MW as shown in Table ES-1 below. This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2016-003 from the previously studied 72 x Vestas 3.45 MW configuration to the 59 x Vestas 4.2 MW + 1 x Vestas 3.6 MW wind turbine configuration for a total generating capacity of 251.4 MW, which is greater than the Interconnection Service (248.4 MW) listed in the GEN-2016-003 Generator Interconnection Agreement (GIA) Appendix A. The customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformer, reactive power devices, and the generation interconnection line. The modification request changes are shown in Table ES-2.

Table ES-1: GEN-2016-003 Existing Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2016-003	248.4	72 x Vestas GS V126 3.45 MW = 248.4 MW	Tap on Badger (515677) to Woodward (515375) 345 kV double circuit (G16-003-TAP 560071)

Table ES-2: GEN-2016-003 Modification Request

<table>
<tr><th>Facility</th><th>Existing</th><th colspan="2">Modification</th></tr>
<tr><td>Point of Interconnection</td><td>Tap on Badger (515677) to Woodward (515375) 345 kV double circuit (G16-003-TAP 560071)</td><td colspan="2">Tap on Badger (515677) to Woodward (515375) 345 kV double circuit (G16-003-TAP 560071)</td></tr>
<tr><td>Configuration/Capacity</td><td>72 x Vestas GS V126 3.45 MW = 248.4 MW</td><td colspan="2">59 x Vestas 4.2 MW + 1 x Vestas 3.6 MW = 251.4 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td>Length = 0.001 miles
R = 0.000000 pu
X = 0.000010 pu
B = 0.000000 pu</td><td colspan="2">Length = 0.1 miles
R = 0.000128 pu
X = 0.005488 pu
B = 0.007800 pu</td></tr>
<tr><td>Main Substation Transformer</td><td>X = 8.0%, R = 0.178%, Winding 180 MVA, Rate 300 MVA</td><td colspan="2">X = 8.5%, R = 0.24%, Winding 168 MVA, Rating 280 MVA</td></tr>
<tr><td>GSU Transformer</td><td>Gen 1 Equivalent Qty: 72:
X = 8.97%, R = 0.696%, Rating 270 MVA</td><td>Gen 1 Equivalent Qty: 59:
X = 5.71%, R = 0.71%, Rating 303.9 MVA</td><td>Gen 2 Equivalent Qty: 1:
X = 5.71%, R = 0.71%, Rating 4 MVA</td></tr>
<tr><td>Equivalent Collector Line</td><td>R = 0.002770 pu
X = 0.003650 pu
B = 0.067230 pu</td><td colspan="2">R = 0.004887 pu
X = 0.005296 pu
B = 0.068256 pu</td></tr>
<tr><td>Reactive Power Devices</td><td>N/A</td><td colspan="2">1 x 40 MVAR 34.5 kV Capacitor Bank</td></tr>
</table>

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.61%. However, SPP determined that while the modification used the same turbine manufacturer, Vestas, the generator model change from GSCOR1 to CP20065718 required short circuit and dynamic stability analyses.

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

Aneden performed the analyses using the modification request data based on the DISIS-2016-002 Group 1 study models:

1. 2017 Winter Peak (2017WP),
2. 2018 Summer Peak (2018SP),
3. 2026 Summer Peak (2026SP),

All analyses were performed using the PTI PSS/E version 33.7 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak models showed that the GEN-2016-003 project needed 7.6 MVAr of reactor shunts on the 34.5 kV bus of the project substation, an increase from the 6.7 MVAr found in the previous DISIS study[1]. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the customer and Transmission Owner. SPP does not require additional reactive requirements based on the results of this analysis.

The results from the short circuit analysis with the updated topology showed that the maximum GEN-2016-003 contribution to three-phase fault currents in the immediate systems at or near GEN-2016-003 was not greater than 0.23 kA for the 2018SP and 2026SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-003 generators online were below 45 kA for the 2018SP and 2026SP models.

The dynamic stability analysis was performed using the three DISIS-2016-002 models 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak. Up to 56 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

The results of the dynamic stability analysis showed that there were no damping or voltage recovery violations 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] Definitive Interconnection System Impact Study Report (DISIS-2016-001-1) – December 22, 2017

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-2016-003. A Modification Request Impact Study is a generation interconnection study performed to evaluate the impacts of modifying the DISIS study assumptions. The determination of the required scope of the study is dependent upon the specific modification requested and how it may impact the results of the DISIS study. Impacting the DISIS results could potentially affect the cost or timing of any Interconnection Request with a later Queue priority date, deeming the requested modification a Material Modification. The criteria sections below include reasoning as to why an analysis was either included or excluded from the scope of study.

All analyses were performed using the PTI PSS/E version 33.7 software. The results of each analysis are presented in the following sections.

1.1 Power Flow

To determine whether power flow analysis is required, SPP evaluates the difference in the real power output at the POI between the existing configuration and the requested modification. Power flow analysis is included if the difference has a significant impact on the results of DISIS study.

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 collector system impedance between the existing configuration and the requested modification. Dynamic stability analysis and short circuit analysis would be required if the differences listed above were determined to have a significant impact on the most recently performed DISIS stability analysis.

1.3 Charging Current Compensation Analysis

SPP requires that a charging current compensation analysis be performed on the requested modification configuration as it is a non-synchronous resource. The charging current compensation analysis determines the capacitive effect at the POI caused by the project's collector system and transmission line's capacitance. A shunt reactor size is determined in order to offset the capacitive effect and maintain zero (0) MVAr flow at the POI while the plant'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-2016-003 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the G16-003-TAP 345 kV bus on the Badger to Woodward 345 kV double circuit. At the time of the posting of this report, GEN-2016-003 is an active IR with a queue status of "IA FULLY EXECUTED/ON SCHEDULE." GEN-2016-003 is a wind farm, has a maximum summer and winter queue capacity of 248.4 MW, and has Energy Resource Interconnection Service (ERIS). GEN-2016-003 has an Interconnection Service amount of 248.4 MW listed in Appendix A of its most recent GIA.

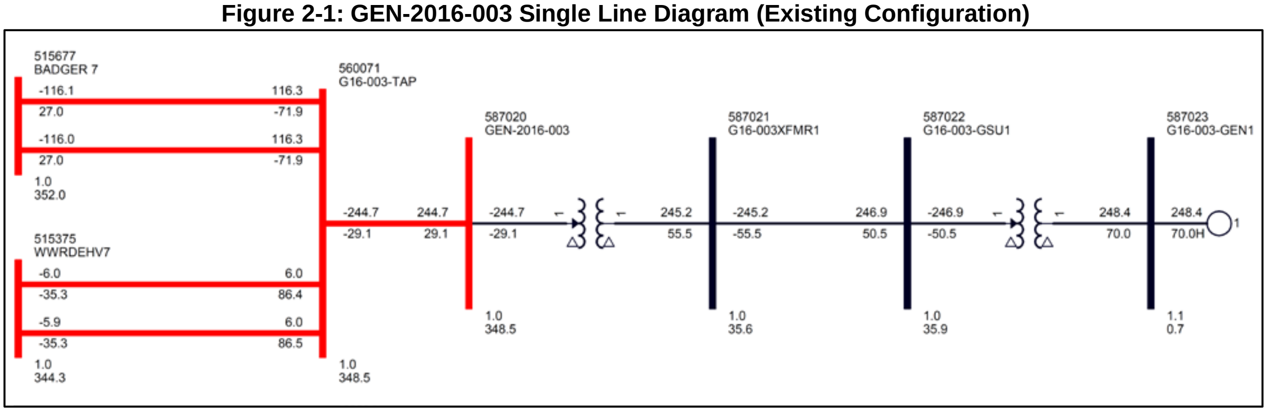
GEN-2016-003 was originally studied as part of Group 1 in the DISIS-2016-001-1 study. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2016-003 configuration.

The GEN-2016-003 project is proposed to interconnect in the Oklahoma Gas & Electric (OKGE) control area with a combined generating capacity of 248.4 MW as shown in Table 2-1 below.

Table 2-1: GEN-2016-003 Existing Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2016-003	248.4	72 x Vestas GS V126 3.45 MW = 248.4 MW	Tap on Badger (515677) to Woodward (515375) 345 kV double circuit (G16-003-TAP 560071)

Figure 2-1: GEN-2016-003 Single Line Diagram (Existing Configuration)



This study has been requested by the Interconnection Customer to evaluate the modification of GEN-2016-003 from the previously studied 72 x Vestas 3.45 MW configuration to the 59 x Vestas 4.2 MW + 1 x Vestas 3.6 MW wind turbine configuration for a total generating capacity of 251.4 MW. In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformer, reactive power devices, and the generation interconnection line. The modification request changes are shown in Figure 2-2 and Table 2-2 below.

This requested modification places the generating capacity of GEN-2016-003 at a greater amount than the Interconnection Service listed in its GIA.

Figure 2-2: GEN-2016-003 Single Line Diagram (Modification Configuration)

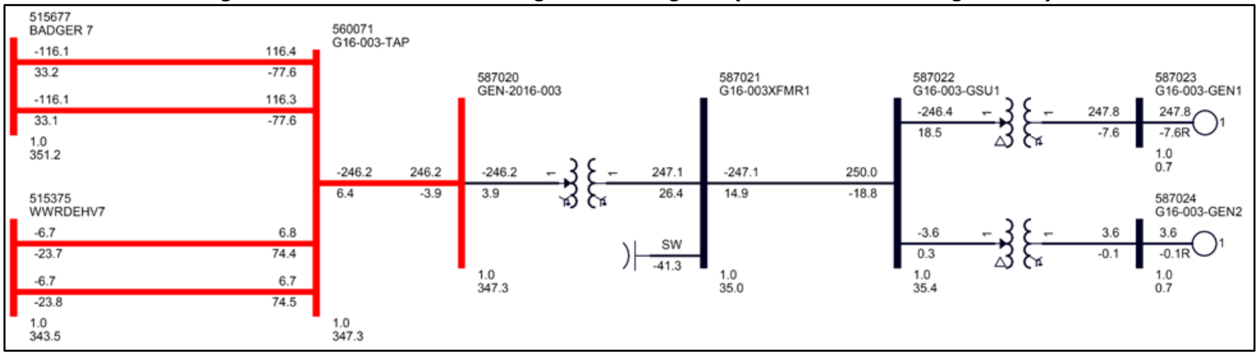


Table 2-2: GEN-2016-003 Modification Request

Facility	Existing	Modification	
Point of Interconnection	Tap on Badger (515677) to Woodward (515375) 345 kV double circuit (G16-003-TAP 560071)	Tap on Badger (515677) to Woodward (515375) 345 kV double circuit (G16-003-TAP 560071)	
Configuration/Capacity	72 x Vestas GS V126 3.45 MW = 248.4 MW	59 x Vestas 4.2 MW + 1 x Vestas 3.6 MW = 251.4 MW	
Generation Interconnection Line	Length = 0.001 miles R = 0.000000 pu X = 0.000010 pu B = 0.000000 pu	Length = 0.1 miles R = 0.000128 pu X = 0.005488 pu B = 0.007800 pu	
Main Substation Transformer	X = 8.0%, R = 0.178%, Winding 180 MVA, Rate 300 MVA	X = 8.5%, R = 0.24%, Winding 168 MVA, Rating 280 MVA	
GSU Transformer	Gen 1 Equivalent Qty: 72: X = 8.97%, R = 0.696%, Rating 270 MVA	Gen 1 Equivalent Qty: 59: X = 5.71%, R = 0.71%, Rating 303.9 MVA	Gen 2 Equivalent Qty: 1: X = 5.71%, R = 0.71%, Rating 4 MVA
Equivalent Collector Line	R = 0.002770 pu X = 0.003650 pu B = 0.067230 pu	R = 0.004887 pu X = 0.005296 pu B = 0.068256 pu	
Reactive Power Devices	N/A	1 x 40 MVAR 34.5 kV Capacitor Bank	

3.0 Existing vs Modification Comparison

To determine which analysis is required, 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-2016-002 Group 1 study models.

The methodology and results of the comparisons are described below. The analysis was completed using PSS/E version 33.7 software.

3.1 POI Injection Comparison

The real power injection at the POI was determined using PSS/E for both the existing configuration and the requested modification with updates for GEN-2016-003. The percentage change in the POI injection before and after the modification request was then compared. If the MW difference was determined to be significant, power flow analysis would be performed to assess the impact of the modification request.

SPP determined that power flow analysis was not required due to the insignificant change (increase of 0.61%) in the real power output at the POI between the existing configuration and requested modification shown in Table 3-1.

Table 3-1: GEN-2016-003 POI Injection Comparison

Interconnection Request	Existing POI Injection from Project (MW)	MRIS POI Injection from Project (MW)	POI Injection Difference from Project %
GEN-2016-003	244.7	246.2	0.61%

It should be noted that the requested modification's POI injection amount of 246.2 MW is less than the Interconnection Service amount of 248.2 MW listed in its GIA. However, this calculation is based on available information at the time of study and may not reflect real-time performance of the generating facility.

3.2 Turbine Parameters Comparison

SPP determined that while the modification used the same turbine manufacturer, Vestas, the generator model change from GSCOR1 to CP20065718 required short circuit and dynamic stability analyses as the 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.

3.3 Equivalent Impedance Comparison Calculation

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

4.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2016-003 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-2016-003 generators and capacitors (if any) were switched out of service while other collector system elements remained in-service. A shunt reactor was tested at the phase's collection substation 34.5 kV bus to set the MVAr flow into the POI to approximately zero. The size of the shunt reactor is equivalent to the charging current value at unity voltage and the compensation provided is proportional to the voltage effects on the charging current (i.e. for voltages above unity, reactive compensation is greater than the size of the reactor).

4.2 Results

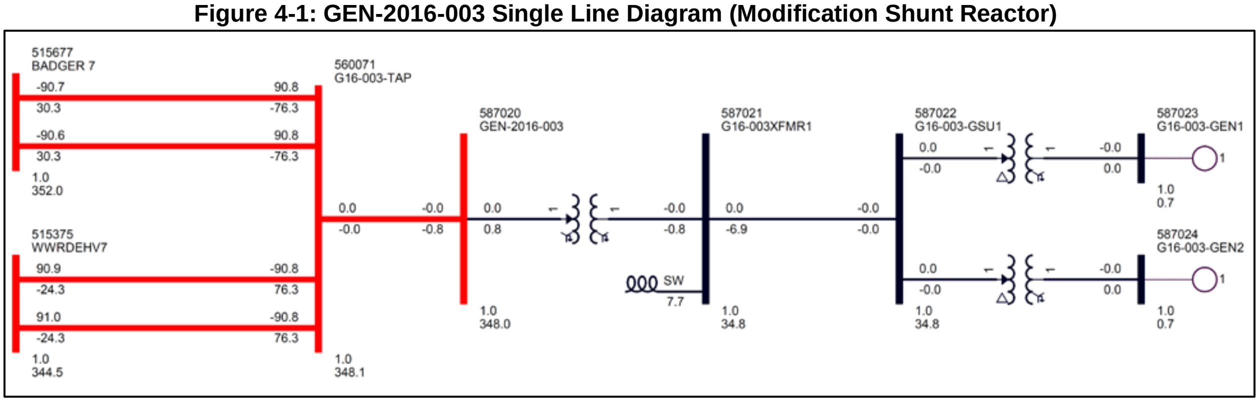
The results from the analysis showed that the GEN-2016-003 project needed an approximately 7.6 MVAr shunt reactor at the project substation, to reduce the POI MVAr to zero. This is an increase from the 6.7 MVAr found in the previous DISIS study[2]. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero. The final shunt reactor requirements for GEN-2016-003 is shown in Table 4-1.

The information gathered from the charging current compensation analysis is provided as information to the customer and Transmission Owner. SPP does not require additional reactive requirements based on the results of this analysis.

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

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)		
			17WP	18SP	26SP
GEN-2016-003	560071	G16-003-TAP 345 kV	7.6	7.6	7.6

Figure 4-1: GEN-2016-003 Single Line Diagram (Modification Shunt Reactor)



[2] Definitive Interconnection System Impact Study Report (DISIS-2016-001-1) – December 22, 2017

5.0 Short Circuit Analysis

A short circuit study was performed using the 2018SP and 2026SP models for GEN-2016-003. 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 345 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels with and without GEN-2016-003 online.

5.2 Results

The results of the short circuit analysis for the 2018SP and 2026SP models are summarized in Table 5-1 through Table 5-3 respectively. The GEN-2016-003 POI bus fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 14.47 kA.

The maximum fault current calculated within 5 buses of the GEN-2016-003 POI was less than 45 kA for the 2018SP and 2026SP models respectively. The maximum GEN-2016-003 contribution to three-phase fault current was about 1.6% and 0.23 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2018SP	14.24	14.46	0.23	1.6%
2026SP	14.24	14.47	0.23	1.6%

Table 5-2: 2018SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	10.6	0.00	0.0%
115	10.9	-0.01	-0.1%
138	44.1	0.06	0.3%
230	21.4	0.00	0.0%
345	32.6	0.23	1.6%
Max	**44.1**	**0.23**	**1.6%**

Table 5-3: 2026SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	10.8	0.00	0.0%
115	10.9	-0.01	-0.1%
138	43.8	0.06	0.3%
230	23.9	0.00	0.0%
345	32.6	0.23	1.6%
Max	**43.8**	**0.23**	**1.6%**

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine configuration change and other modifications to the GEN-2016-003 project. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix C. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix A. The simulation plots can be found in Appendix D.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested 59 x Vestas 4.2 MW (CP20065718) + 1 x Vestas 3.6 MW (CP20065718) configuration for the GEN-2016-003 generating facilities. This stability analysis was performed using PTI's PSS/E version 33.7 software.

The stability models were developed using the models from DISIS-2016-002 for Group 1. The modifications requested for the GEN-2016-003 project was used to create modified stability models for this impact study.

The modified dynamics model data for the DISIS-2016-001 Group 1 request, GEN-2016-003, is provided in Appendix A. The modified power flow models and associated dynamics database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2016-003 and other equally and prior queued projects in Group 1. In addition, voltages of five (5) buses away from the POI of GEN-2016-003 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 520 (AEPW), 524 (OKGE), 525 (WFEC), 526 (SPS), 531 (MIDW), 534 (SUNC), 536 (WERE) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

6.2 Fault Definitions

Aneden simulated the faults previously simulated for GEN-2016-003 and selected additional fault events for GEN-2016-003 as required. The new set of faults were simulated using the modified study models. The fault events included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers. The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 2017 Winter Peak, 2018 Summer Peak, and the 2026 Summer Peak models.

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT39-3PH	P1	3 phase fault on G16-003-TAP 345kV (560071) to WWRDEHV7 345kV (515375) line CKT 1, near G16-003-TAP. a. Apply fault at the G16-003-TAP 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT40-3PH	P1	3 phase fault on HITCHLAND 7 345kV (523097) to HITCHLAND 6 230kV (523095) to HITCHLD_TR01 13.2kV (523091) transformer CKT 1, near HITCHLAND 7 345kV. a. Apply fault at the HITCHLAND 7 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT41-3PH (17WP ONLY)	P1	3 phase fault on HITCHLAND 7 345kV (523097) to FINNEY 7 345kV (523853) line CKT 1, near HITCHLAND 7. a. Apply fault at the HITCHLAND 7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT42-3PH	P1	3 phase fault on HITCHLAND 7 345kV (523097) to POTTER_CO 7 345kV (523961) line CKT 1, near HITCHLAND 7. a. Apply fault at the HITCHLAND 7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT43-3PH	P1	3 phase fault on WWRDEHV7 345kV (515375) to THISTLE7 345kV (539801) line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT44-3PH	P1	3 phase fault on WWRDEHV7 345kV (515375) to BORDER 7 345kV (515458) line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT45-3PH	P1	3 phase fault on WWRDEHV7 345kV (515375) to WWRDEHV4 138kV (515376) to WWDEHV31 13.8kV (515795) transformer CKT 1, near WWRDEHV7 345 kV. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT65-3PH	P1	3 phase fault on MATHWSN7 345kV (515497) to TATONGA7 345kV (515407) line CKT 1, near MATHWSN7. a. Apply fault at the MATHWSN7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT48-SB (Invalid, Not Studied)*	P4	Stuck Breaker at WWRDEHV7 (515375). a. Apply single phase fault at WWRDEHV7 bus. b. Clear fault after 16 cycles and trip the following elements c. WWRDEHV7 (515375) - THISTLE7 (539801), line CKT 1 d. WWRDEHV7 345kV (515375) / WWRDEHV4 138kV (515376) / WWDEHV31 13.8kV (515795) transformer CKT 1.
FLT45-PO1	P6	**Prior Outage of WWRDEHV7 345kV (515375) to THISTLE7 345kV (539801) line CKT 2.** 3 phase fault on WWRDEHV7 345kV (515375) / WWRDEHV4 138kV (515376) / WWDEHV31 13.8kV (515795) transformer CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 bus. b. Clear fault after 5 cycles and trip the faulted line.
FLT9001-3PH	P1	3 phase fault on G16-003-TAP 345kV (560071) to BADGER 7 345kV (515677) line CKT 1, near G16-003-TAP. a. Apply fault at the G16-003-TAP 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

*Based on the breaker diagram[3] this previously studied fault is no longer valid and was not included

[3] Part 3 - CEII - OGE System Operating Diagram_2628.pdf

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9002-3PH	P1	3 phase fault on BADGER 7 345kV (515677) to BVRCNTY7 345kV (515554) line CKT 1, near BADGER 7. a. Apply fault at the BADGER 7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1	3 phase fault on BADGER 7 345kV (515677) to GEN-2011-014 345kV (515686) line CKT 1, near BADGER 7. a. Apply fault at the BADGER 7 345kV bus. **Trip generator G11-014-GEN1 (515678).** **Trip generator G11-014-GEN2 (515682).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9004-3PH	P1	3 phase fault on BADGER 7 345kV (515677) to GEN-2015-082 345kV (585190) line CKT 1, near BADGER 7. a. Apply fault at the BADGER 7 345kV bus. **Trip generator G15-082-GEN1 (585193).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on BVRCNTY7 345kV (515554) to G14-037-TAP (560010) 345kV line CKT 1, near BVRCNTY7. a. Apply fault at the BVRCNTY7 345kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT9006-3PH	P1	3 phase fault on BVRCNTY7 345kV (515554) to GEN-2013-030 (583760) 345kV line CKT 1, near BVRCNTY7. a. Apply fault at the BVRCNTY7 345kV bus. **Trip generator G13-030-GEN2 (583766).** **Trip generator G13-030-GEN1 (583763).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9007-3PH	P1	3 phase fault on BVRCNTY7 345kV (515554) to BALKOW 7 (515618) 345kV line CKT 1, near BVRCNTY7. a. Apply fault at the BVRCNTY7 345kV bus. **Trip generator BALKOWG1 (515658).** **Trip generator BALKOWG2 (515659).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 phase fault on BVRCNTY7 345kV (515554) to PALDR2W7 (515590) 345kV line CKT 1, near BVRCNTY7. a. Apply fault at the BVRCNTY7 345kV bus. **Trip generator G08-047-GEN1 (573506).** **Trip generator G08-047-GEN2 (573510).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	P1	3 phase fault on G14-037-TAP (560010) to HITCHLAND 7 (523097) 345kV line CKT 1, near G14-037-TAP. a. Apply fault at the G14-037-TAP 345kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT9010-3PH	P1	3 phase fault on G14-037-TAP (560010) to GEN-2014-037 (584210) 345kV line CKT 1, near G14-037-TAP. a. Apply fault at the G14-037-TAP 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip generator G14-037-GEN2 (584216).** **Trip generator G14-037-GEN1 (584213).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9011-3PH (18SP and 26SP ONLY)	P1	3 phase fault on HITCHLAND 7 (523097) to WALKEMEYER 7 (523823) 345kV line CKT 1, near HITCHLAND 7. a. Apply fault at the HITCHLAND 7 345kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT9012-3PH	P1	3 phase fault on HITCHLAND 7 (523097) to NOVUS1 (523112) 345kV line CKT 1, near HITCHLAND 7. a. Apply fault at the HITCHLAND 7 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip generator G06-044GEN1A (579373).** **Trip generator G06-044GEN1B (579380).** **Trip generator NOVUS_WND 1 (523107).** **Trip generator G06-044GEN2A (579376).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9013-3PH	P1	3 phase fault on HITCHLAND 7 (523097) to GEN-2010-014 (576395) 345kV line CKT 1, near HITCHLAND 7. a. Apply fault at the HITCHLAND 7 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip generator G10-014-GEN2 (576410).** **Trip generator G10-014-GEN1 (576400).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9014-3PH	P1	3 phase fault on HITCHLAND 7 (523097) to NOBLE_WND 7 (523101) 345kV line CKT 1, near HITCHLAND 7. a. Apply fault at the HITCHLAND 7 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip generator NBLWND-WTG11 (523121).** **Trip generator NBLWND-WTG21 (523122).** **Trip generator NBLWND-WTG31 (523123).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9015-3PH	P1	3 phase fault on HITCHLAND 7 (523097) to FREWHELCOL17 (523215) 345kV line CKT 1, near HITCHLAND 7. a. Apply fault at the HITCHLAND 7 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip generator FREWHEL-GEN2 (599150).** **Trip generator FREWHEL-GEN1 (599148).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9016-3PH	P1	3 phase fault on WWRDEHV7 345kV (515375) to G07621119-20 345kV (515599) line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator GW_WTG12 (585414).** **Trip generator GW_WTG11 (585413).** **Trip generator GW_WTG22 (585418).** **Trip generator GW_WTG21 (585417).** **Trip generator CB_WTG2 (585426).** **Trip generator CB_WTG1 (585423).** **Trip generator PC1_WTG2 (585436).** **Trip generator PC1_WTG1 (585433).** **Trip generator PC2_WTG2 (585446).** **Trip generator PC2_WTG1 (585443).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9017-3PH	P1	3 phase fault on G07621119-20 345kV (515599) to GREAT_WESTRN (585410) line CKT 1, near G07621119-20. a. Apply fault at the G07621119-20 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator GW_WTG12 (585414).** **Trip generator GW_WTG11 (585413).** **Trip generator GW_WTG22 (585418).** **Trip generator GW_WTG21 (585417).** **Trip generator CB_WTG2 (585426).** **Trip generator CB_WTG1 (585423).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9018-3PH	P1	3 phase fault on G07621119-20 345kV (515599) to PRSIMN_CRK1 (585430) line CKT 1, near G07621119-20. a. Apply fault at the G07621119-20 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator PC1_WTG2 (585436).** **Trip generator PC1_WTG1 (585433).** **Trip generator PC2_WTG2 (585446).** **Trip generator PC2_WTG1 (585443).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9019-3PH	P1	3 phase fault on BORDER 7 (515458) to G1149&G1504 (583090) 345kV line CKT 1, near BORDER 7. a. Apply fault at the BORDER 7 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip generator G1149&G1504G2 (583096).** **Trip generator G11-049-GEN1 (583093).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9020-3PH	P1	3 phase fault on BORDER 7 (515458) to G16-120-TAP 345kV (587964) line CKT 1, near BORDER 7. a. Apply fault at the BORDER 7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9021-3PH	P1	3 phase fault on WWRDEHV7 345kV (515375) to TATONGA7 345kV (515407) line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9022-3PH	P1	3 phase fault on TATONGA7 345kV (515407) to SLNGWND7 345kV (515582) line CKT 1, near TATONGA7. a. Apply fault at the TATONGA7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator SELIG WTG1 (599059).** **Trip generator SILNGWG1 (515587).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9023-3PH	P1	3 phase fault on TATONGA7 345kV (515407) to GEN-2015-029 (584700) line CKT 1, near TATONGA7. a. Apply fault at the TATONGA7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator GEN-2015-029-GEN1 (584703).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9024-3PH	P1	3 phase fault on TATONGA7 345kV (515407) to CRSRDSW7 345kV (515448) line CKT 1, near TATONGA7. a. Apply fault at the TATONGA7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator CRSRD-WTG1 (599099).** **Trip generator CRSRD-WTG2 (599101).** **Trip generator CRSRDX-WTG2 (599103).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9025-3PH	P1	3 phase fault on TATONGA7 345kV (515407) to MAMTHPW7 345kV (515585) line CKT 1, near TATONGA7. a. Apply fault at the TATONGA7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator MMTHPLN_GEN1 (599136).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9026-3PH	P1	3 phase fault on TATONGA7 345kV (515407) to MATHWSN7 345kV (515497) line CKT 1, near TATONGA7. a. Apply fault at the TATONGA7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9027-3PH	P1	3 phase fault on THISTLE7 345kV (539801) to BUFFALO7 345kV (532782) line CKT 1, near THISTLE7. a. Apply fault at the THISTLE7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9028-3PH	P1	3 phase fault on THISTLE7 345kV (539801) to G16-005-TAP 345kV (560072) line CKT 1, near THISTLE7. a. Apply fault at the THISTLE7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9029-3PH	P1	3 phase fault on THISTLE7 345kV (539801) to THISTLE4 138 kV (539804) to THISTLE T1 13.8 kV (539802) transformer, near THISTLE7 345 kV. a. Apply fault at the THISTLE7 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT43-PO1	P6	**Prior Outage of WWRDEHV7 345kV (515375) to THISTLE7 345kV (539801) line CKT 2.** 3 phase fault on WWRDEHV7 345kV (515375) to THISTLE7 345kV (539801) line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9026-PO2	P6	**Prior Outage of TATONGA7 345kV (515407) to MATHWSN7 345kV (515497) line CKT 2.** 3 phase fault on TATONGA7 345kV (515407) to MATHWSN7 345kV (515497) line CKT 1, near TATONGA7. a. Apply fault at the TATONGA7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT39-PO3	P6	**Prior Outage of G16-003-TAP 345kV (560071) to WWRDEHV7 345kV (515375) line CKT 2.** 3 phase fault on G16-003-TAP 345kV (560071) to WWRDEHV7 345kV (515375) line CKT 1, near G16-003-TAP. a. Apply fault at the G16-003-TAP 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-PO3	P6	**Prior Outage of G16-003-TAP 345kV (560071) to WWRDEHV7 345kV (515375) line CKT 2.** 3 phase fault on G16-003-TAP 345kV (560071) to BADGER 7 345kV (515677) line CKT 1, near G16-003-TAP. a. Apply fault at the G16-003-TAP 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-PO4	P6	**Prior Outage of G16-003-TAP 345kV (560071) to BADGER 7 345kV (515677) line CKT 2.** 3 phase fault on G16-003-TAP 345kV (560071) to BADGER 7 345kV (515677) line CKT 1, near G16-003-TAP. a. Apply fault at the G16-003-TAP 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT39-PO4	P6	**Prior Outage of G16-003-TAP 345kV (560071) to BADGER 7 345kV (515677) line CKT 2.** 3 phase fault on G16-003-TAP 345kV (560071) to WWRDEHV7 345kV (515375) line CKT 1, near G16-003-TAP. a. Apply fault at the G16-003-TAP 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9002-PO5	P6	**Prior Outage of BADGER 7 345kV (515677) to BVRCNTY7 345kV (515554) line CKT 2.** 3 phase fault on BADGER 7 345kV (515677) to BVRCNTY7 345kV (515554) line CKT 1, near BADGER 7. a. Apply fault at the BADGER 7 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9005-PO6	P6	**Prior Outage of BVRCNTY7 345kV (515554) to G14-037-TAP (560010) 345kV line CKT 2.** 3 phase fault on BVRCNTY7 345kV (515554) to G14-037-TAP (560010) 345kV line CKT 1, near BVRCNTY7. a. Apply fault at the BVRCNTY7 345kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT9009-PO7	P6	**Prior Outage of G14-037-TAP (560010) to HITCHLAND 7 (523097) 345kV line CKT 2.** 3 phase fault on G14-037-TAP (560010) to HITCHLAND 7 (523097) 345kV line CKT 1, near G14-037-TAP. a. Apply fault at the G14-037-TAP 345kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT1001-SB	P4	**Stuck Breaker on at WOODWARD (515375).** a. Apply single-phase fault at WOODWARD (515375) on the 345kV bus. b. After 16 cycles, trip the WOODWARD (515375) 345kV bus on the WOODWARD – TATONGA (515407) 345kV line CKT 1 c. Trip the WOODWARD 345kV (515375) to WOODWARD 138kV (515376) WOODWARD 13.8kV (515799) XFMR line CKT 2, and remove the fault.
FLT1002-SB	P4	**Stuck Breaker on at WOODWARD (515375).** a. Apply single-phase fault at WOODWARD (515375) on the 345kV bus. b. After 16 cycles, trip the WOODWARD (515375) 345kV bus on the WOODWARD – TATONGA (515407) 345kV line CKT 2. c. Trip the WOODWARD 345kV (515375) to WOODWARD 138kV (515376) WOODWARD 13.8kV (515795) XFMR line CKT 1, and remove the fault.
FLT1003-SB	P4	**Stuck Breaker on at WOODWARD (515375).** a. Apply single-phase fault at WOODWARD (515375) on the 345kV bus. b. After 16 cycles, trip the WOODWARD (515375) to G16-003-Tap (560071)345 kV line CKT 2. c. Trip the WOODWARD (515375) to G07621119-20 (515599) 345 kV line CKT 1, and remove the fault. **Trip generators connected to Bus (515599).**
FLT1004-SB	P4	**Stuck Breaker on at BADGER (515677).** a. Apply single-phase fault at BADGER (515677) on the 345kV bus. b. After 16 cycles, trip the BADGER (515677) to Beaver County (515554) 345 kV line CKT 2. c. Trip the BADGER (515677) to GEN-2011-014 (515686) line CKT 1 and remove the fault. **Trip generator G11-014-GEN2 (515682).** **Trip generator G11-014-GEN1 (515678).**
FLT1005-SB	P4	**Stuck Breaker on at BADGER (515677).** a. Apply single-phase fault at BADGER (515677) on the 345kV bus. b. After 16 cycles, trip the BADGER (515677) to Beaver County (515554) 345 kV line CKT 2. c. Trip the BADGER (515677) to Beaver County (515554) 345 kV line CKT 1 and remove the fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT1006-SB	P4	**Stuck Breaker on at BADGER (515677).** a. Apply single-phase fault at BADGER (515677) on the 345kV bus. b. After 16 cycles, trip the BADGER (515677) to G16-003-TAP (560071) 345 kV line CKT 1. c. Trip the BADGER (515677) to GEN-2011-014 (515686) line CKT 1 and remove the fault. **Trip generator G11-014-GEN2 (515682).** **Trip generator G11-014-GEN1 (515678).**
FLT1007-SB	P4	**Stuck Breaker on at BADGER (515677).** a. Apply single-phase fault at BADGER (515677) on the 345kV bus. b. After 16 cycles, trip the BADGER (515677) to G16-003-TAP (560071) 345 kV line CKT 1. c. Trip the BADGER (515677) to G16-003-TAP (560071) 345 kV line CKT 2 and remove the fault.
FLT1008-SB	P4	**Stuck Breaker on at BADGER (515677).** a. Apply single-phase fault at BADGER (515677) on the 345kV bus. b. After 16 cycles, trip the BADGER (515677) to Beaver County (515554) 345 kV line CKT 1. c. Trip the BADGER (515677) to G16-003-TAP (560071) 345 kV line CKT 2 and remove the fault.

6.3 Results

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

Table 6-2: GEN-2016-003 Dynamic Stability Results

Fault ID	17WP			18SP			26SP		
	Volt. Recovery	Volt. Violation	Stable	Volt. Recovery	Volt. Violation	Stable	Volt. Recovery	Volt. Violation	Stable
FLT39-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT40-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT41-3PH (17WP ONLY)	Pass	Pass	Stable						
FLT42-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT43-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT44-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT45-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT65-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH (18SP and 26SP ONLY)				Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	17WP			18SP			26SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9029-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT43-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT45-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT39-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT39-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

There were no damping or voltage recovery violations 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 Generating Capacity Greater Than Interconnection Service

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 which is stated in its GIA. This is allowable as long as they install the proper control and protection devices and the requested modification is not determined to be a Material Modification.

7.1 Results

The requested modification of GEN-2016-003 has a generating capacity of 251.4 MW and an Interconnection Service amount of 248.4 MW listed in Appendix A of its most recent GIA. This 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.

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 resulted in similar dynamic stability and short circuit analyses and that the prior study power flow results are not negatively impacted.

This determination implies that any network upgrades already required by GEN-2016-003 would not be negatively impacted and that no new upgrades are required due to the requested modification, thus not resulting in material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.

9.0 Conclusions

The Interconnection Customer for GEN-2016-003 requested a Modification Request Impact Study to assess the impact of the turbine and facility changes including a configuration change to 59 x Vestas 4.2 MW + 1 x Vestas 3.6 MW wind turbines for a total generating capacity of 251.4 MW. This modified generating capacity of 251.4 MW is greater than the Interconnection Service amount of 248.4 MW listed in Appendix A of the most recent GEN-2016-003 GIA. The customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

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

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.61%. However, SPP determined that while the modification used the same turbine manufacturer, Vestas, the generator model change from GSCOR1 to CP20065718 required short circuit and dynamic stability analyses.

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

The results of the charging current compensation analysis performed using the 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak models showed that the GEN-2016-003 project needed 7.6 MVAr of reactor shunts on the 34.5 kV bus of the project substation, an increase from the 6.7 MVAr found in the previous DISIS study[4]. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the customer and Transmission Owner. SPP does not require additional reactive requirements based on the results of this analysis.

The results from the short circuit analysis with the updated topology showed that the maximum GEN-2016-003 contribution to three-phase fault currents in the immediate systems at or near GEN-2016-003 was not greater than 0.23 kA for the 2018SP and 2026SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-003 generators online were below 45 kA for the 2018SP and 2026SP models.

The dynamic stability analysis was performed using the three DISIS-2016-002 models 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak. Up to 56 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

The results of the dynamic stability analysis showed that there were no damping or voltage recovery violations observed during the simulated faults. Additionally, the project was found to

[4] Definitive Interconnection System Impact Study Report (DISIS-2016-001-1) – December 22, 2017

stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

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

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

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.