GEN-2015-065 & GEN-2016-067

Impact Restudy for

Generator Modification

(Turbine Change)

Published January 2019

By Generator Interconnection

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
1/18/2019	Generator Interconnection		Initial Posting

EXECUTIVE SUMMARY

The GEN-2015-065 & GEN-2016-067 Interconnection Customer has requested a modification to its Interconnection Request. This system impact restudy was performed to determine the effects of changing wind turbine generators from the previously studied 120 Siemens 2.3 MW wind turbine generators (for a total capacity of 276 MW) to 105 Siemens/Gamesa 2.625 MW wind turbine generators (for a total capacity of 275.625 MW). The Point of Interconnection (POI) for these requests remain unchanged at the Sunflower Electric Power Corporation (SUNC) Mingo 345kV substation.

This study was performed by Aneden Consulting to determine whether the request for modification is considered Material. The study report follows this executive summary.

While performing the stability analysis, the consultant noted that after the prior outage of the Red Willow to the Point of Interconnection substation 345 kV line, a three-phase fault on the Mingo 345kV to Setab 345kV line caused an undervoltage trip of GEN-2015-065 & GEN-2016-067. The output of the project may have to be curtailed to about 200 MW after the prior outage to prevent the undervoltage trip of the project.

The restudy showed that no other stability problems were found during the summer and the winter peak conditions as a result of changing to the Siemens/Gamesa 2.625 MW wind turbine generators. Additionally, the project wind farm 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.

With the assumptions outlined in this report and with all the required network upgrades in place, GEN-2015-065 & GEN-2016-067 with 105 Siemens/Gamesa 2.625 MW wind turbine generators should be able to interconnect reliably to the SPP transmission grid. This restudy confirms that the requested modification in wind turbine generators is not considered Material.

A low-wind/no-wind condition analysis was performed for this modification request. To prevent reactive power injection into the transmission system during low/no wind operation, the Interconnection Customer will be required to install approximately 24.4 MVAr of shunt reactors to be located on the 345 kV bus or install and utilize an equivalent means of compensating for the injection of reactive power into the transmission system at the Point of Interconnection.

It should be noted that this study analyzed the requested modification to change generator technology, manufacturer, and layout. This study analyzed many of the most probable contingencies, but it is not an all-inclusive list and cannot account for every operational situation. It is likely that the customer may be required to reduce its generation output to 0 MW, 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.

Aneden Consulting report follows.

Submitted to

Southwest Power Pool

Report On

GEN-2015-065 & GEN-2016-067 Modification Request Impact Study

Revision R1

Date of Submittal
January 16, 2019

anedenconsulting.com

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDICES

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2015-065 & GEN-2016-067, an active generation interconnection request with point of interconnection (POI) on the Mingo 345 kV substation.

The GEN-2015-065 and GEN-2016-067 projects were proposed to interconnect in the Sunflower Corp. (SUNC) control area with a combined capacity of 276 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2015-065 and GEN-2016-067 to change turbine configuration change to a total of 105 x Siemens/Gamesa 2.625 MW for a total capacity of 275.625 MW. Both projects were modeled as a single equivalent generator. In addition, the modification request included changes to the generation interconnection line, collection system and the main substation transformer. The modification request changes are shown in Table ES-2 below.

Table ES-1: Existing GEN-2015-065 & GEN-2016-067 Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2015-065	202.4	88 x Siemens 2.3MW	Mingo 345kV Substation (531451)
GEN-2016-067	73.6	32 x Siemens 2.3 MW	Mingo 345kV Substation (531451)

Table ES-2: GEN-2015-065 & GEN-2016-067 Modification Request

Facility	Existing	Modification Request
Point of Interconnection	Mingo 345kV Substation (531451)	Mingo 345kV Substation (531451)
Configuration/Capacity	88 x Siemens 2.3MW = 202.4 MW 32 x Siemens 2.3MW = 73.6 MW	105 x Siemens/Gamesa 2.625 MW turbines (275.625 MW)
Generation Interconnection Line(s)	Length = 7.5 miles R = 0.000400 pu X = 0.003100 pu B = 0.004200 pu *Zero impedance line is included in original case	Length = 9.196 miles R = 0.000505 pu X = 0.004634 pu B = 0.077858 pu
Main Substation Transformer	T1: Z = 8.0%, Rating 225 MVA T2: Z = 8.0%, Rating 180 MVA	T1: Z = 11.0%, Rating 225 MVA T2: Z = 11.0%, Rating 225 MVA
Equivalent Collector Line 1	R = 0.002283 pu X = 0.003118 pu B = 0.029680 pu	R = 0.009178 pu X = 0.012510 pu B = 0.099339 pu
Equivalent Collector Line 2	R = 0.006142 pu X = 0.008520 pu B = 0.055290 pu	R = 0.006510 pu X = 0.008433 pu B = 0.066016 pu
Capacitor (C1)	N/A	2 x 15 MVAr
Capacitor (C2)	N/A	2 x 15 MVAr

GEN-2015-065 and GEN-2016-067 were originally studied as part of Group 4 in the DISIS-2015-002 and DISIS-2016-001 in April 2016 and January 2017 respectively. Aneden performed reactive power analysis, short circuit analysis and dynamic stability analysis using the modification request data based on the DISIS-2016-001 ReStudy #1 Group 4 study models:

1. 2016 Winter Peak (2016WP),
2. 2017 Summer Peak (2017SP) and
3. 2025 Summer Peak (2025SP).

All analyses were performed using the PTI PSS/E version 32 software and the results are summarized below.

A power factor analysis was not performed as there was no change in the point of interconnection for GEN-2015-065 and GEN-2016-067.

The results of the reactive power analysis, also known as the low-wind/no-wind condition analysis, performed using all three models showed that the combined GEN-2015-065 & GEN-2016-067 project may require a 24.4 MVAr shunt reactor on the 345 kV bus of the project substation. The shunt reactor is needed to reduce the reactive power transfer at the POI to approximately zero during low/no wind conditions while the generation interconnection project remains connected to the grid.

The results from short circuit analysis showed that the maximum change in the fault currents in the immediate systems at or near GEN-2015-065 & GEN-2016-067 was .4139 kA. All three-phase current levels with the GEN-2015-065 & GEN-2016-067 generator online were below 23 kA in the 2017SP and 2025SP models.

The dynamic stability analysis was performed using the three loading scenarios 2016 Winter Peak, 2017 Summer Peak and 2025 Summer Peak simulating up to 52 contingencies that included three-phase faults, three phase faults on prior outage cases, and single-line-to-ground faults stuck breakers faults.

After the prior outage of the Red Willow to the Point of Interconnection substation 345 kV line, a three-phase fault on the Mingo 345kV to Setab 345kV line caused a undervoltage trip of GEN-2015-065 & GEN-2016-067. The output of the project may have to be curtailed to about 200 MW after the prior outage to prevent the undervoltage trip of the project.

There were no other machine rotor angle damping or transient voltage recovery violations observed in the simulated fault events. Additionally, the project wind farm was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

The results of this Study show that the GEN-2015-065 & GEN-2016-067 Modification Request sdoes not constitute a material modification.

1.0 Introduction

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2015-065 & GEN-2016-067, an active generation interconnection request with point of interconnection (POI) on the Mingo 345 kV substation.

The GEN-2015-065 and GEN-2016-067 projects were proposed to interconnect in the Sunflower Corp. (SUNC) control area with a combined capacity of 276 MW as shown in Table 1-1 below. Details of the modification request as provided in Section 2.0 below.

Table 1-1: Existing GEN-2015-065 & GEN-2016-067 Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2015-065	202.4	88 x Siemens 2.3MW	Mingo 345kV Substation (531451)
GEN-2016-067	73.6	32 x Siemens 2.3 MW	Mingo 345kV Substation (531451)

1.1 Scope

The Study included short circuit, power factor, reactive power and dynamic stabilities. The methodology, assumptions and results of the analyses are presented in the following five main sections:

1. Project and Modification Request
2. Reactive Power Analysis
3. Short Circuit Analysis
4. Dynamic Stability Analysis
5. Conclusions

Aneden performed a reactive power analysis, short circuit analysis and dynamic stability analysis using a set of modified study models developed using the modification request data and the three DISIS-2016-001 ReStudy #4 study models:

1. 2016 Winter Peak (2016WP),
2. 2017 Summer Peak (2017SP), and
3. 2025 Summer Peak (2025SP).

All analyses were performed using the PTI PSS/E version 32 software. The results of each analysis are presented in the following sections.

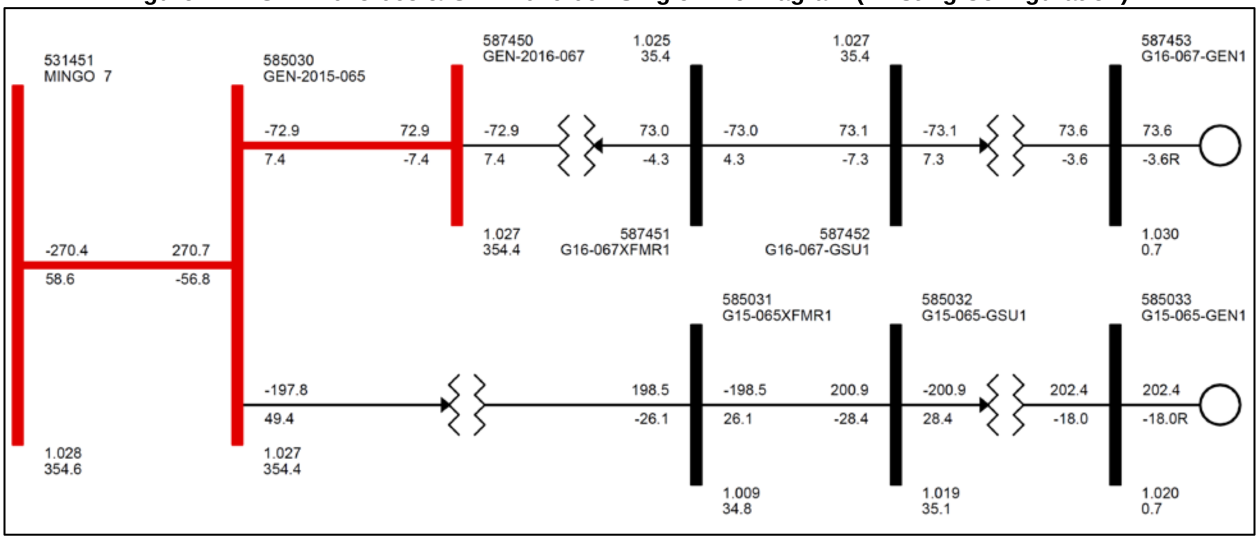
1.2 Study Limitations

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

Figure 2-1 shows the power flow model single line diagram for the existing GEN-2015-065 & GEN-2016-067 configuration. GEN-2015-065 and GEN-2016-067 were originally studied as part of Group 4 in the DISIS-2015-002 and DISIS-2016-001 in April 2016 and January 2017 respectively.

Figure 2-1: GEN-2015-065 & GEN-2016-067 Single Line Diagram (Existing Configuration)



The GEN-2015-065 & GEN-2016-067 Modification Request included a turbine change to 105 x Siemens/Gamesa 2.625 MW for a total capacity of 275.625 MW. In addition, the modification request also included changes to the collection system, the main substation transformer and the generation interconnection line. The major modification request changes are shown in Figure 2-2 and Table 2-1 below.

Figure 2-2: GEN-2015-065 & GEN-2016-067 Single Line Diagram (New Configuration)

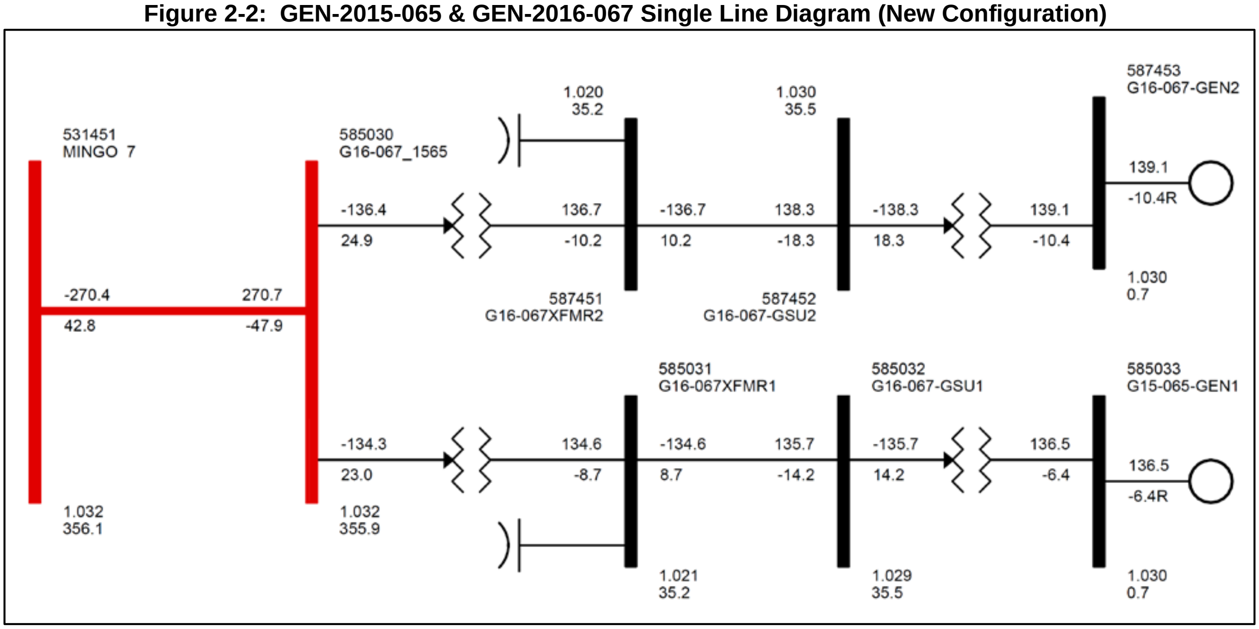


Table 2-1: GEN-2015-065 & GEN-2016-067 Modification Request

Facility	Existing	Modification Request
Point of Interconnection	Mingo 345kV Substation (531451)	Mingo 345kV Substation (531451)
Configuration/Capacity	88 x Siemens 2.3MW = 202.4 MW 32 x Siemens 2.3MW = 73.6 MW	105 x Siemens/Gamesa 2.625 MW turbines (275.625 MW)
Generation Interconnection Line(s)	Length = 7.5 miles R = 0.000400 pu X = 0.003100 pu B = 0.004200 pu *Zero impedance line is included in original case	Length = 9.196 miles R = 0.000505 pu X = 0.004634 pu B = 0.077858 pu
Main Substation Transformer	T1: Z = 8.0%, Rating 225 MVA T2: Z = 8.0%, Rating 180 MVA	T1: Z = 11.0%, Rating 225 MVA T2: Z = 11.0%, Rating 225 MVA
Equivalent Collector Line 1	R = 0.002283 pu X = 0.003118 pu B = 0.029680 pu	R = 0.009178 pu X = 0.012510 pu B = 0.099339 pu
Equivalent Collector Line 2	R = 0.006142 pu X = 0.008520 pu B = 0.055290 pu	R = 0.006510 pu X = 0.008433 pu B = 0.066016 pu
Capacitor (C1)	N/A	2 x 15 MVAr
Capacitor (C2)	N/A	2 x 15 MVAr

3.0 Reactive Power Analysis

The reactive power analysis, also known as the low-wind/no-wind condition analysis, was performed for GEN-2015-065 & GEN-2016-067 to determine the reactive power contribution from the project's interconnection line and collector transformer and cables during low/no wind conditions while the project is still connected to the grid and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

3.1 Methodology and Criteria

For the GEN-2015-065 & GEN-2016-067 project, the generator was switched out of service while other collector system elements remained in-service. A shunt reactor was tested at the study project substation high side bus to bring the MVAr flow into the POI down to approximately zero.

3.2 Results

The results from the reactive power analysis showed that the GEN-2015-065 & GEN-2016-067 project required approximately 24.4 MVAr shunt reactance at the high side of the project substation, to reduce the POI MVAr to zero. This represents the contributions from the project collector systems. Figure 3-1 illustrates the shunt reactor size required to reduce the POI voltage to approximately zero. Reactive compensation can be provided either by discrete reactive devices or by the generator itself if it possesses that capability.

Figure 3-1: GEN-2015-065 & GEN-2016-067 Single Line Diagram (Shunt Reactor)

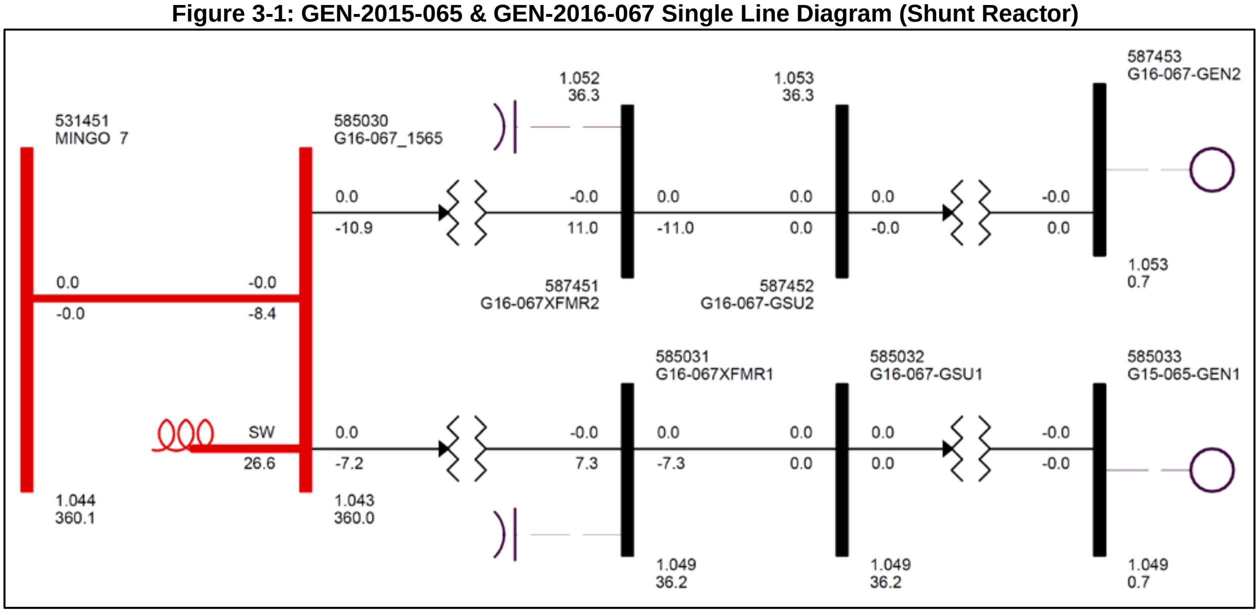


Table 3-1 shows the shunt reactor size determined for the three study models used in the assessment.

Table 3-1: Shunt Reactor Size for Low Wind Study

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)		
			16WP	17SP	25SP
GEN-2015-065 & GEN-2016-067	531451	MINGO 7	24.4	24.4	24.4

4.0 Short Circuit Analysis

A short-circuit study was performed on the power flow models for the 2017SP and 2025SP models for GEN-2015-065 & GEN-2016-067 using the modified Cluster Scenario models. The detail results of the short-circuit analysis are provided in Appendix A.

4.1 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 the project online.

4.2 Results

The results of the short circuit analysis are summarized in Table 4-1 and Table 4-2 for the 2017SP and 2025SP models, respectively. The maximum increase in fault current was about .4139 kA. The maximum fault current calculated within 5 buses with GEN-2015-065 & GEN-2016-067 was less than 23 kA for the 2017SP and 2025SP models.

Table 4-1: 2017SP Short Circuit Results

Bus Distance	Max. Change (kA)	Max %Change
0	0.3923	6.97%
1	0.1898	2.09%
2	0.1205	1.54%
3	0.0664	0.62%
4	0.0245	0.25%
5	-0.0007	-0.02%

Table 4-2: 2025SP Short Circuit Results

Bus Distance	Max. Change (kA)	Max %Change
0	0.4028	7.04%
1	0.4139	3.49%
2	0.2381	2.54%
3	0.0687	0.64%
4	0.0474	0.48%
5	0.0055	0.13%

5.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine change and other modifications to the GEN-2015-065 & GEN-2016-067 project. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix B. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix C. The simulation plots can be found in Appendix D.

5.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested 105 x Siemens/Gamesa 2.625 MW turbine configuration for the GEN-2015-065 & GEN-2016-067 generating facility. This stability analysis was performed using PTI's PSS/E version 32 software.

The stability models were developed using the models from the DISIS-2016-001 ReStudy #1 (DISIS-2016-001-1) for Group 4 including network upgrades identified in that restudy. The modifications requested to project GEN-2015-065 & GEN-2016-067 were used to create modified stability models for this impact study.

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. The modified dynamics model data for the DISIS-2016-001-1 (Group 4) request, GEN-2015-065 & GEN-2016-067 is provided in Appendix C.

During the fault simulations, the active power (PELEC), reactive power (QELEC) and terminal voltage (ETERM) were monitored for GEN-2015-065 & GEN-2016-067 and other equally and prior queued projects in Group 4. In addition, voltages of five (5) buses away from the POI of GEN-2015-065 & GEN-2016-067 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) and 640 (NPPD) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

5.2 Fault Definitions

Aneden selected the fault events simulated specifically for GEN-2015-065 & GEN-2016-067 in the DISIS-2016-001 Group 4 study and included additional faults based on the location of the point of interconnection. The new set of faults were simulated using the modified study models. The fault events include three phase faults with reclosing, stuck breaker, and prior outage events. Single-line-to-ground (SLG) fault impedance values were determined by applying a fault on the base case large enough to produce a 0.6 pu voltage value on the faulted bus. This SLG value was then used for the SLG faults.

The simulated faults are listed and described in Table 5-1 below. These contingencies were applied to the modified 2016 Winter Peak, 2017 Summer Peak, and the 2025 Summer Peak models.

Table 5-1: Fault Definitions

Fault ID	Fault Descriptions
FLT01-3PH	3 phase fault on the Post Rock 345kV (530583) to Axtell 345kV (640065) CKT 1, near Post Rock. a. Apply fault at the Post Rock 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.
FLT02-3PH	3 phase fault on the Axtell 345kV (640065) to Sweetwater 345 kV (640374) CKT 1, near Axtell. a. Apply fault at the Axtell 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.
FLT03-3PH	3 phase fault on the Mingo 345kV (531451) to Red Willow 345kV (640325) CKT 1, near Mingo. a. Apply fault at the Mingo 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.
FLT04-3PH	3 phase fault on the Mingo 345kV (531451) to Setab 345kV (531465) CKT 1, near Mingo. a. Apply fault at the Mingo 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.
FLT05-3PH	3 phase fault on the Setab 345kV (531465) to Holcomb 345kV (531449) CKT 1, near Setab. a. Apply fault at the Setab 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.
FLT06-3PH	3 phase fault on the Holcomb 345kV (531449) to Buckner 345kV (531501) CKT 1, near Holcomb. a. Apply fault at the Holcomb 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.
FLT07-3PH	3 phase fault on the Setab 345kV (531465) to Setab 115kV (531464) to Setab 13.8kV (531259) XFMR CKT 1, near Setab 345kV. a. Apply fault at the Setab 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT08-3PH	3 phase fault on the Red Willow 345kV (640325) to Gentleman 345kV (640183) CKT 1, near Red Willow. a. Apply fault at the Red Willow 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.
FLT09-3PH	3 phase fault on the Red Willow 345kV (640325) to Red Willow 115kV (640326) to Red Willow 13.8kV (640327) XFMR CKT 1, near Red Willow. a. Apply fault at the Red Willow 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT10-3PH	3 phase fault on the Gentleman 345kV (640183) to Sweetwater 345kV (640374) CKT 1, near Gentleman. a. Apply fault at the Gentleman 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.

Table 5-1 continued

Fault ID	Fault Descriptions
FLT11-3PH	3 phase fault on the Holcomb 345kV (531449) to Finney 345kV (523853) CKT 1, near Holcomb. a. Apply fault at the Holcomb 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.
FLT12-3PH	3 phase fault on the Holcomb 345kV (531449) to Holcomb 115kV (531448) to Holcomb 13.8kV (531450) XFMR CKT 1, near Holcomb 345kV. a. Apply fault at the Holcomb 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT13-3PH	3 phase fault on the Gentleman 345kV (640183) to Keystone 345kV (640252) CKT 1, near Gentleman. a. Apply fault at the Gentleman 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.
FLT14-3PH	3 phase fault on the Beach 115kV (530557) to Hoxie 115kV (530556) CKT 1, near Beach. a. Apply fault at the Beach 115kV 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.
FLT15-3PH	3 phase fault on the Colby 115kV (530555) to Atwood 115kV (530554) CKT 1, near Colby. a. Apply fault at the Colby 115kV 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. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT16-3PH	3 phase fault on the Colby 115kV (530555) to Seguin Tap 115kV (530682) CKT 1, near Colby. a. Apply fault at the Colby 115kV 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.
FLT17-3PH	3 phase fault on the Colby 115kV (530555) to Mingo 115kV (531429) CKT 1, near Colby. a. Apply fault at the Colby 115kV 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.
FLT18-3PH	3 phase fault on the Mingo 115kV (531429) to Pheasant Run 115kV (530559) CKT 1, near Mingo. a. Apply fault at the Mingo 115kV 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.
FLT19-3PH	3 phase fault on the Mingo 115kV (531429) to Brewster 115kV (531351) CKT 1, near Mingo. a. Apply fault at the Mingo 115kV 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.
FLT20-3PH	3 phase fault on the Mingo 115kV (531429) to Mingo 345kV (531451) to Mingo 13.8kV (531452) XFMR CKT 1, near Mingo 115kV. a. Apply fault at the Mingo 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

Table 5-1 continued

Fault ID	Fault Descriptions
FLT21-3PH	3 phase fault on the Pheasant Run 115kV (530559) to Seguin 115kV (530683) CKT 1, near Pheasant Run. a. Apply fault at the Pheasant Run 115kV 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.
FLT22-3PH	3 phase fault on the Pheasant Run 115kV (530559) to Grinnell 115kV (531412) CKT 1, near Pheasant Run. a. Apply fault at the Pheasant Run 115kV 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.
FLT23-3PH	3 phase fault on the Gove 115kV (531411) to Arnold 115kV (531409) CKT 1, near Gove. a. Apply fault at the Gove 115kV 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.
FLT24-3PH	3 phase fault on the Arnold 115kV (531409) to Ransom 115kV (531414) CKT 1, near Arnold. a. Apply fault at the Arnold 115kV 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.
FLT25-3PH	3 phase fault on the Atwood 115kV (530554) to Atwood SW 115kV (531364) CKT 1, near Atwood. a. Apply fault at the Atwood 115kV 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.
FLT26-3PH	3 phase fault on the Atwood 115kV (530554) to Beaver Valley 115kV (531488) CKT 1, near Atwood. a. Apply fault at the Atwood 115kV 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.
FLT27-PO FLT18-PO1	**Prior Outage of Mingo to Brewster 115kV**. 3 phase fault on the Mingo – Pheasant Run 115kV line. a. Prior outage Mingo (531429) 115kV to Brewster (531351) 115kV (solve network for steady state solution). b. 3 phase fault on the Mingo (531429) 115kV to Pheasant Run (530559) 115kV, near Mingo 115kV. c. Leave fault on for 5 cycles, then trip the faulted line in (b).
FLT28-PO FLT4-PO2	**Prior Outage of Mingo to Red Willow 345kV**. 3 phase fault on the G15-061-Tap – Setab 345kV line. a. Prior outage Mingo (531451) 345kV to Red Willow (640325) 345kV (solve network for steady state solution). b. 3 phase fault on the Mingo (531451) 345kV to Setab (531465) 345kV, near G15-051-Tap 345kV. c. Leave fault on for 5 cycles, then trip the faulted line in (b).
FLT29-PO FLT17-PO3	**Prior Outage of Setab to Mingo 345kV**. 3 phase fault on the Mingo – Colby 115kV line. a. Prior outage Setab (531465) 345kV to Mingo (531451) 345kV (solve network for steady state solution). b. 3 phase fault on the Mingo (531429) 115kV to Colby (530555) 115kV, near Mingo 115kV. c. Leave fault on for 5 cycles, then trip the faulted line in (b).
FLT30-SB	**Mingo 115kV Stuck Breaker** a. Apply single phase fault at the Mingo (531429)115kV bus on the Mingo – Brewster (531351) 115kV line. b. Wait 16 cycles, and then trip Mingo (531429) to Brewster (531351) 115kV. c. Trip Mingo (531429) to Colby (530555) 115kV and remove the fault.

Table 5-1 continued

Fault ID	Fault Descriptions
FLT31-SB	**Mingo 345kV Stuck Breaker** a. Apply single phase fault at the Mingo (531451) 345kV bus on the Mingo – Red Willow (640325) 345kV line. b. Wait 16 cycles, and then trip Mingo (531451) to Red Willow (640325) 345kV. c. Trip Mingo (531451) 345kV to Mingo (531429) 115kV to Mingo (531452) 13.8kV transformer and remove the fault.
FLT32-SB	**Holcomb 345kV Stuck Breaker** a. Apply single phase fault at the Holcomb (531449) 345kV bus on the Holcomb – Buckner (531501) 345kV line. b. Wait 16 cycles, and then trip Holcomb (531449) to Buckner (531501) 345kV. c. Trip Holcomb (531449) 345kV to Holcomb (531448) 115kV to Holcomb (531450) 13.8kV transformer and remove the fault.
FLT9001-3PH	3 phase fault on the GENTLMN3 345kV (640183) to THEDFRD3 345kV (640500), near GENTLMN3. a. Apply fault at the GENTLMN3 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.
FLT9002-3PH	3 phase fault on the GENTLMN3 345kV (640183) to GENTLMN4 230kV (640184) to GENTLEMANT29 13.8kV (643066), near GENTLMN3 345kV. a. Apply fault at the GENTLMN3 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9003-3PH	3 phase fault on the GENTLMN3 345kV (640183) to GENTLM2G 24kV (640011), near GENTLMN3 345kV. a. Apply fault at the GENTLMN3 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer. Trip generator at GENTLM2G
FLT9004-3PH	3 phase fault on the MINGO 345kV (531451) to MINGO 115kV (531429) to MINGTER1 13.8kV (531452), near MINGO 345kV. a. Apply fault at the MINGO 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT05-PO2	Prior Outage of the MINGO (531451) 345kV to REDWILO3 (640325) 345kV 3 phase fault on the Setab 345kV (531465) to Holcomb 345kV (531449) CKT 1, near Setab. a. Apply fault at the Setab 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.
FLT07-PO2	Prior Outage of the MINGO (531451) 345kV to REDWILO3 (640325) 345kV 3 phase fault on the Setab 345kV (531465) to Setab 115kV (531464) to Setab 13.8kV (531259) XFMR CKT 1, near Setab 345kV. a. Apply fault at the Setab 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT17-PO2	Prior Outage of the MINGO (531451) 345kV to REDWILO3 (640325) 345kV. 3 phase fault on the Colby 115kV (530555) to Mingo 115kV (531429) CKT 1, near Colby. a. Apply fault at the Colby 115kV 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.
FLT18-PO2	Prior Outage of the MINGO (531451) 345kV to REDWILO3 (640325) 345kV. 3 phase fault on the Mingo 115kV (531429) to Pheasant Run 115kV (530559) CKT 1, near Mingo. a. Apply fault at the Mingo 115kV 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.

Table 5-1 continued

Fault ID	Fault Descriptions
FLT19-PO2	Prior Outage of the MINGO (531451) 345kV to REDWILO3 (640325) 345kV. 3 phase fault on the Mingo 115kV (531429) to Brewster 115kV (531351) CKT 1, near Mingo. a. Apply fault at the Mingo 115kV 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.
FLT08-PO3	Prior Outage of the MINGO (531451) 345kV to SETAB (531465) 345kV. 3 phase fault on the Red Willow 345kV (640325) to Gentleman 345kV (640183) CKT 1, near Red Willow. a. Apply fault at the Red Willow 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.
FLT09-PO3	Prior Outage of the MINGO (531451) 345kV to SETAB (531465) 345kV. 3 phase fault on the Red Willow 345kV (640325) to Red Willow 115kV (640326) to Red Willow 13.8kV (640327) XFMR CKT 1, near Red Willow. a. Apply fault at the Red Willow 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT17-PO3	Prior Outage of the MINGO (531451) 345kV to SETAB (531465) 345kV. 3 phase fault on the Colby 115kV (530555) to Mingo 115kV (531429) CKT 1, near Colby. a. Apply fault at the Colby 115kV 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.
FLT18-PO3	Prior Outage of the MINGO (531451) 345kV to SETAB (531465) 345kV. 3 phase fault on the Mingo 115kV (531429) to Pheasant Run 115kV (530559) CKT 1, near Mingo. a. Apply fault at the Mingo 115kV 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.
FLT19-PO3	Prior Outage of the MINGO (531451) 345kV to SETAB (531465) 345kV. 3 phase fault on the Mingo 115kV (531429) to Brewster 115kV (531351) CKT 1, near Mingo. a. Apply fault at the Mingo 115kV 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.
FLT05-PO4	Prior Outage of the MINGO (531451) 345kV to MINGO (531429) 115kV to MINGTER1 (531452) 13.8kV transformer. 3 phase fault on the Setab 345kV (531465) to Holcomb 345kV (531449) CKT 1, near Setab. a. Apply fault at the Setab 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.
FLT07-PO4	Prior Outage of the MINGO (531451) 345kV to MINGO (531429) 115kV to MINGTER1 (531452) 13.8kV transformer. 3 phase fault on the Setab 345kV (531465) to Setab 115kV (531464) to Setab 13.8kV (531259) XFMR CKT 1, near Setab 345kV. a. Apply fault at the Setab 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT08-PO4	Prior Outage of the MINGO (531451) 345kV to MINGO (531429) 115kV to MINGTER1 (531452) 13.8kV transformer. 3 phase fault on the Red Willow 345kV (640325) to Gentleman 345kV (640183) CKT 1, near Red Willow. a. Apply fault at the Red Willow 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.

Table 5-1 continued

Fault ID	Fault Descriptions
FLT09-PO4	Prior Outage of the MINGO (531451) 345kV to MINGO (531429) 115kV to MINGTER1 (531452) 13.8kV transformer. 3 phase fault on the Red Willow 345kV (640325) to Red Willow 115kV (640326) to Red Willow 13.8kV (640327) XFMR CKT 1, near Red Willow. a. Apply fault at the Red Willow 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9100-SB	**Setab 345kV Stuck Breaker** a. Apply single phase fault at the SETAB 7 (531465) 345kV bus on the SETAB 7 (531465) - Mingo 7 (531451) 345kV line. b. Wait 16 cycles, and then trip SETAB 7 (531465) - Mingo 7 (531451) 345kV line. c. Trip SETAB 7 (531465) - HOLCOMB7 (531449) 345kV line and remove the fault.
FLT9200-SB	**REDWILO3 345kV Stuck Breaker** a. Apply single phase fault at the REDWILO3 (640325) 345kV bus on the REDWILO3 (640325) - Mingo 7 (531451) 345kV line. b. Wait 16 cycles, and then trip REDWILO3 (640325) - Mingo 7 (531451) 345kV line. c. Trip REDWILO3 (640325) - GENTLMN3 (640183) 345kV line and remove the fault.

5.3 Results

There were no damping or voltage recovery violations observed during the simulations and the system returned to stable conditions except for one fault condition described below.

FLT04-PO2, prior outage on the GEN-2015-065 & GEN-2016-067 POI to Red Willow 345kV line followed by the three phase fault on the Mingo 345kV to Setab 345kV line caused the system to become unstable where GEN-2015-065 & GEN-2016-067 is connected radially only through Mingo 345 kV/115 kV transformer. To prevent this issue, GEN-2015-065 & GEN-2016-067 may have to be curtailed to 200 MW after the loss of either the GEN-2015-065 & GEN-2016-067 POI to Red Willow 345kV line or the Mingo to Setab 345 kV line.

Table 5-2 shows the curtailment requires for FLT04-PO2 described above. GEN-2015-065 & GEN-2016-067 output may have to be limited to the amounts listed in Table 5-2.

Table 5-2: GEN-2015-065 & GEN-2016-067 Output Limits for FLT04-PO2 (MW)

Fault	2016WP	2017SP	2025SP
FLT04-PO2	200	215	225

Table 5-3 shows the results of the fault events simulated for each of the models. The associated stability plots are provided in Appendix D. Additionally, the project wind farm 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.

Table 5-3: GEN-2015-065 & GEN-2016-067 Dynamic Stability Results

Fault ID	2016WP	2017SP	2025SP
FLT01-3PH	Stable	Stable	Stable
FLT02-3PH	Stable	Stable	Stable
FLT03-3PH	Stable	Stable	Stable
FLT04-3PH	Stable	Stable	Stable
FLT05-3PH	Stable	Stable	Stable
FLT06-3PH	Stable	Stable	Stable
FLT07-3PH	Stable	Stable	Stable
FLT08-3PH	Stable	Stable	Stable
FLT09-3PH	Stable	Stable	Stable
FLT10-3PH	Stable	Stable	Stable
FLT11-3PH	Stable	Stable	Stable
FLT12-3PH	Stable	Stable	Stable
FLT13-3PH	Stable	Stable	Stable
FLT14-3PH	Stable	Stable	Stable
FLT15-3PH	Stable	Stable	Stable
FLT16-3PH	Stable	Stable	Stable
FLT17-3PH	Stable	Stable	Stable
FLT18-3PH	Stable	Stable	Stable
FLT19-3PH	Stable	Stable	Stable
FLT20-3PH	Stable	Stable	Stable
FLT21-3PH	Stable	Stable	Stable
FLT22-3PH	Stable	Stable	Stable
FLT23-3PH	Stable	Stable	Stable
FLT24-3PH	Stable	Stable	Stable
FLT25-3PH	Stable	Stable	Stable
FLT26-3PH	Stable	Stable	Stable
FLT30-SB	Stable	Stable	Stable
FLT31-SB	Stable	Stable	Stable
FLT32-SB	Stable	Stable	Stable
FLT9001-3PH	N/A	N/A	Stable
FLT9002-3PH	Stable	Stable	Stable
FLT9003-3PH	Stable	Stable	Stable
FLT9004-3PH	Stable	Stable	Stable
FLT9100-SB	Stable	Stable	Stable
FLT9200-SB	Stable	Stable	Stable
FLT18-PO1	Stable	Stable	Stable

Table 5-3 continued

Fault ID	2016WP	2017SP	2025SP
FLT04-PO2	Unstable GEN-2015-065 & GEN-2016-067 Tripped on Undervoltage. Project Output Curtailed to 200 MW to prevent trip	GEN-2015-065 & GEN-2016-067 Tripped on Undervoltage. Project Output Curtailed to 215 MW to prevent trip	GEN-2015-065 & GEN-2016-067 Tripped on Undervoltage. Project Output Curtailed to 225 MW to prevent trip
FLT05-PO2	Stable	Stable	Stable
FLT07-PO2	Stable	Stable	Stable
FLT17-PO2	Stable	Stable	Stable
FLT18-PO2	Stable	Stable	Stable
FLT19-PO2	Stable	Stable	Stable
FLT08-PO3	Stable	Stable	Stable
FLT09-PO3	Stable	Stable	Stable
FLT17-PO3	Stable	Stable	Stable
FLT18-PO3	Stable	Stable	Stable
FLT19-PO3	Stable	Stable	Stable
FLT05-PO4	Stable	Stable	Stable
FLT07-PO4	Stable	Stable	Stable
FLT08-PO4	Stable	Stable	Stable
FLT09-PO4	Stable	Stable	Stable

6.0 Conclusions

The Interconnection Customer for GEN-2015-065 & GEN-2016-067 requested a Modification Request Impact Study to assess the impact of the turbine and facility changes presented in Table 6-1 below.

Table 6-1: Modification Request

Facility	Existing	Modification Request
Point of Interconnection	Mingo 345kV Substation (531451)	Mingo 345kV Substation (531451)
Configuration/Capacity	88 x Siemens 2.3MW = 202.4 MW 32 x Siemens 2.3MW = 73.6 MW	105 x Siemens/Gamesa 2.625 MW turbines (275.625 MW)
Generation Interconnection Line(s)	Length = 7.5 miles R = 0.000400 pu X = 0.003100 pu B = 0.004200 pu *Zero impedance line is included in original case	Length = 9.196 miles R = 0.000505 pu X = 0.004634 pu B = 0.077858 pu
Main Substation Transformer	T1: Z = 8.0%, Rating 225 MVA T2: Z = 8.0%, Rating 180 MVA	T1: Z = 11.0%, Rating 225 MVA T2: Z = 11.0%, Rating 225 MVA
Equivalent Collector Line 1	R = 0.002283 pu X = 0.003118 pu B = 0.029680 pu	R = 0.009178 pu X = 0.012510 pu B = 0.099339 pu
Equivalent Collector Line 2	R = 0.006142 pu X = 0.008520 pu B = 0.055290 pu	R = 0.006510 pu X = 0.008433 pu B = 0.066016 pu
Capacitor (C1)	N/A	2 x 15 MVAr
Capacitor (C2)	N/A	2 x 15 MVAr

A power factor analysis was not performed as there was no change in the point of interconnection for GEN-2015-065 & GEN-2016-067.

The results of the reactive power analysis, also known as the low-wind/no-wind condition analysis, performed using all three models showed that the combined GEN-2015-065 & GEN-2016-067 project may require a 24.4 MVAr shunt reactor on the 345 kV bus of the project substation. The shunt reactor is needed to reduce the reactive power transfer at the POI to approximately zero during low/no wind conditions while the generation interconnection project remains connected to the grid.

The results from short circuit analysis showed that the maximum change in the fault currents in the immediate systems at or near GEN-2015-065 & GEN-2016-067 was .4139 kA. The largest fault current calculated was below 23 kA in the 2017SP and 2025SP models.

The results of the dynamic stability analysis showed that after the prior outage of the Red Willow to the Point of Interconnection substation 345 kV line, a three-phase fault on the Mingo 345kV to Setab 345kV line caused a undervoltage trip of GEN-2015-065 & GEN-2016-067. The output of the project may have to be curtailed to about 200 MW after the prior outage to prevent the undervoltage trip of the project.

There were no other machine rotor angle damping or transient voltage recovery violations observed in the simulated fault events. Additionally, the project wind farm 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.

In conclusion, the results of this Study showed that the Modification Request shown in Table 6-1 do not constitute a material modification.