GEN-2016-115

Impact Restudy for Generator Modification

Published July 2019
By SPP Generator Interconnections Dept.

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
07/30/2019	SPP	Initial report issued.

CONTENTS

SUMMARY

The GEN-2016-115 Interconnection Customer has requested a modification to its 300 MW Interconnection Request. This system impact restudy was performed to determine the effects of changing wind turbine generators from 150 Vestas 2.0 MW wind turbine generators (for a total of 300 MW) to 51 Vestas V150 4.2 MW, 22 Vestas V120 2.2 MW, and 18 Vestas V110 2.0 MW wind turbine generators (for a total of 298.6 MW). In addition, the modification request included changes to the generation interconnection line, collection system and the generator substation transformer. The point of interconnection (POI) for GEN-2016-115 remains at the Holt County 345kV Substation.

This study was performed by Aneden Consulting to determine whether the request for modification is considered Material. A short circuit analysis, a low-wind/no-wind condition analysis, and stability analysis was performed for this modification request. The study report follows this executive summary.

The generating facility will be required to maintain a 95% lagging (providing VARs) and 95% leading (absorbing VArs) power factor in accordance with FERC Order 827. Additionally, the project will be required to install approximately 22.9 MVArs of reactor shunts on its substation 345 kV buses or provide an alternate means of reactive power compensation. 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/no-wind conditions.

The results of the dynamic stability analysis showed that with both GEN-2014-021 and GEN-2016-115 generating facilities installing Power Plant Controllers to maintain the voltages at the Holt 345 kV bus and the Rock Creek 345 kV bus respectively, 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 requested modification is not considered Material.

It should be noted that this study analyzed the requested modification to change generator technology and layout. Powerflow analysis was not performed. 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.

A: CONSULTANT'S MATERIAL MODIFICATION STUDY REPORT

See next page for the Consultant's Material Modification Study report.

Aneden Consulting

Submitted to

Southwest Power Pool

SPP Southwest Power Pool

Report On

GEN-2016-115
Modification Request Impact Study

Revision R3

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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-2016-115, an active generation interconnection request with point of interconnection (POI) on the Transource Missouri, LLC (Transource) Holt County 345 kV substation.

The GEN-2016-115 project was proposed to interconnect in the Kansas City Power and Light (KCPL) control area with a capacity of 300 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2016-115 to change turbine configuration to a total of 36 x Vestas V150 4.2 MW (Gen 1) + 15 x Vestas V150 4.2 MW (Gen 2) + 22 x Vestas V120 2.2 MW (Gen 3) + 18 x Vestas V110 2.0 MW (Gen 4) wind turbines for a total capacity of 298.6 MW. In addition, the modification request included changes to the collection system, generator substation transformer, and generation interconnection line. The modification request changes are shown in Table ES-2 below.

Table ES-1: Existing GEN-2016-115 Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2016-115	300	150 x Vestas V110 2.0 MW	Transource's Holt County 345 kV substation (541510)

Table ES-2: GEN-2016-115 Modification Request

<table>
<tr><th>Facility</th><th>Existing</th><th colspan="4">Modification Request</th></tr>
<tr><td>Point of Interconnection</td><td>Holt County 345 kV switching station (541510)</td><td colspan="4">Holt County 345 kV switching station (541510)</td></tr>
<tr><td>Configuration/Capacity</td><td>150 x Vestas V110 2.0 MW = 300 MW</td><td colspan="4">36 x Vestas V150 4.2 MW (Gen 1) + 15 x Vestas V150 4.2 MW (Gen 2) + 22 x Vestas V120 2.2 MW (Gen 3) + 18 x Vestas V110 2.0 MW (Gen 4) = 298.6 MW</td></tr>
<tr><td rowspan="4">Generation Interconnection Line</td><td>Length = 14.6 miles</td><td colspan="2">GEN-2016-115 generator substation – GEN-2014-021 generator substation = 12.44 miles</td><td colspan="2">GEN-2014-021 generator substation - POI = 15.25 miles</td></tr>
<tr><td>R = 0.001450 pu</td><td colspan="2">R = 0.000794 pu</td><td colspan="2">R = 0.000536 pu</td></tr>
<tr><td>X = 0.009300 pu</td><td colspan="2">X = 0.006197 pu</td><td colspan="2">X = 0.007515 pu</td></tr>
<tr><td>B = 0.098440 pu</td><td colspan="2">B = 0.076013 pu</td><td colspan="2">B = 0.13245 pu</td></tr>
<tr><td rowspan="2">Main Substation Transformer</td><td rowspan="2">Z = 11.1%, Winding 192 MVA, Rating 320 MVA</td><td colspan="2">Transformer 1:</td><td colspan="2">Transformer 2:</td></tr>
<tr><td colspan="2">Z = 9.5%, Winding 100 MVA Rating 167 MVA</td><td colspan="2">Z = 9.5%, Winding 100 MVA Rating 167 MVA</td></tr>
<tr><td rowspan="2">GSU Transformer</td><td>Equivalent Qty: 150</td><td>Gen 1 Equivalent Qty: 36:</td><td>Gen 2 Equivalent Qty: 15:</td><td>Gen 3 Equivalent Qty: 22:</td><td>Gen 4 Equivalent Qty: 18:</td></tr>
<tr><td>Z = 7.8%, Rating 315 MVA</td><td>Z = 9.9%, Rating 185.4 MVA</td><td>Z = 9.9%, Rating 77.3 MVA</td><td>Z = 9.6%, Rating 50.6 MVA</td><td>Z = 9.8%, Rating 41.4 MVA</td></tr>
<tr><td rowspan="4">Equivalent Collector Line</td><td>Equivalent Collector Line:</td><td>Equivalent Collector Line 1:</td><td colspan="3">Equivalent Collector Line 2:</td></tr>
<tr><td>R = 0.002410 pu</td><td>R = 0.013568 pu</td><td colspan="3">R = 0.023152 pu</td></tr>
<tr><td>X = 0.003860 pu</td><td>X = 0.014070 pu</td><td colspan="3">X = 0.023852 pu</td></tr>
<tr><td>B = 0.224040 pu</td><td>B = 0.056629 pu</td><td colspan="3">B = 0.094058 pu</td></tr>
<tr><td rowspan="2">Reactive Power Devices</td><td rowspan="2">N/A</td><td colspan="2">Capacitor 1:</td><td colspan="2">Capacitor 2:</td></tr>
<tr><td colspan="2">1 x 20 MVAR 34.5 kV Capacitor Bank</td><td colspan="2">1 x 44 MVAR 34.5 kV Capacitor Bank</td></tr>
</table>

In this study, the GEN-2016-115 345 kV generation interconnection line was connected to the GEN-2014-021 main substation. The GEN-2014-021 substation was then connected to the point of interconnection at Transource's Holt County 345 kV substation, via another 15.25 miles.
GEN-2016-115 was last studied as part of Group 13 in the DISIS-2016-002. Aneden performed reactive power analysis, short circuit analysis and dynamic stability analysis using the modification request data on the initial DISIS-2016-002 Group 13 study models.

All analyses were performed using the PTI PSS/E version 33.7 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-2016-115.

The results of the reactive power analysis, also known as the low-wind/no-wind condition analysis, performed using the three main models showed that the GEN-2016-115 project may require 22.9 MVAr of shunt reactors on the 34.5 kV buses 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-2016-115 was approximately 0.26 kA for the 2018 Summer Peak and 2026 Summer Peak respectively. All three-phase fault current levels with the GEN-2016-115 generator online were below 43 kA for the 2018SP models and 2026SP models.

The dynamic stability analysis was performed using the three models from DISIS-2016-002 models 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak. Up to 48 contingencies were simulated, which included three-phase faults, three phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

During some of the fault simulations, the GEN-2014-021 2 MW wind turbine generator (WTG) power output was observed to drop a few second after the fault was cleared. The power drop was investigated and the cause was associated with how fast the WTG's was able to exit the High Voltage Ride Through (HVRT) mode. The WTG dynamic model VC18084500 RTPitchRiseLevelOut (CON J+12) parameter was adjustesd from the default value of 1.10 pu to 1.11 pu to resolve this issue.

The results of the dynamic stability analysis showed that with both GEN-2014-021 and GEN-2016-115 generating facilities installing Power Plant Controllers to maintain the voltages at the Holt 345 kV bus and the Rock Creek 345 kV bus respectively, there were no machine rotor angle damping or transient voltage recovery violations observed in the remaining simulated fault events associated with this modification request study. Additionally, the project wind farm was found to stay connected during the other 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-2016-115 Modification Request, with both GEN-2014-021 and GEN-2016-115 generating facilities installing Power Plant Controllers to maintain the voltage at the POI, does 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-2016-115, an active generation interconnection request with point of interconnection (POI) at the Transource Missouri, LLC (Transource) Holt County 345 kV switching station.

The GEN-2016-115 project was proposed to interconnect in the Kansas City Power and Light (KCPL) control area with a combined capacity of 300 MW as shown in Table 1-1 below. Details of the modification request are provided in Section 2.0 below.

Table 1-1: Existing GEN-2016-115 Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2016-115	300	150 x Vestas V110 2.0 MW	Transource's Holt County 345 kV substation (541510)

1.1 Scope

The Study included reactive power, short circuit and dynamic stability analyses. 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

The analyses were performed using a set of modified study models developed using the modification request data and the three initial DISIS-2016-002 study models:

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

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

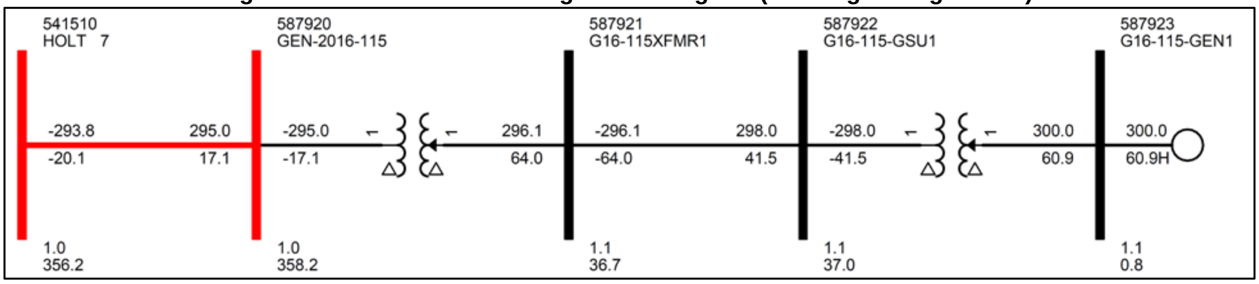
1.2 Study Limitations

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-2016-115 configuration. GEN-2016-115 was originally studied as part of Group 13 in the DISIS-2016-002 study.

Figure 2-1: GEN-2016-115 Single Line Diagram (Existing Configuration)



The GEN-2016-115 Modification Request included a turbine configuration change to a total of 36 x Vestas V150 4.2 MW (Gen 1) + 15 x Vestas V150 4.2 MW (Gen 2) + 22 x Vestas V120 2.2 MW (Gen 3) + 18 x Vestas V110 2.0 MW (Gen 4) wind turbines for a total capacity of 298.6 MW. In addition, the modification request also included changes to the collection system, generator substation transformer, and generation interconnection line. The major modification request changes are shown in Figure 2-2 and Table 2-1 below.

Figure 2-2: GEN-2016-115 Single Line Diagram (New Configuration)

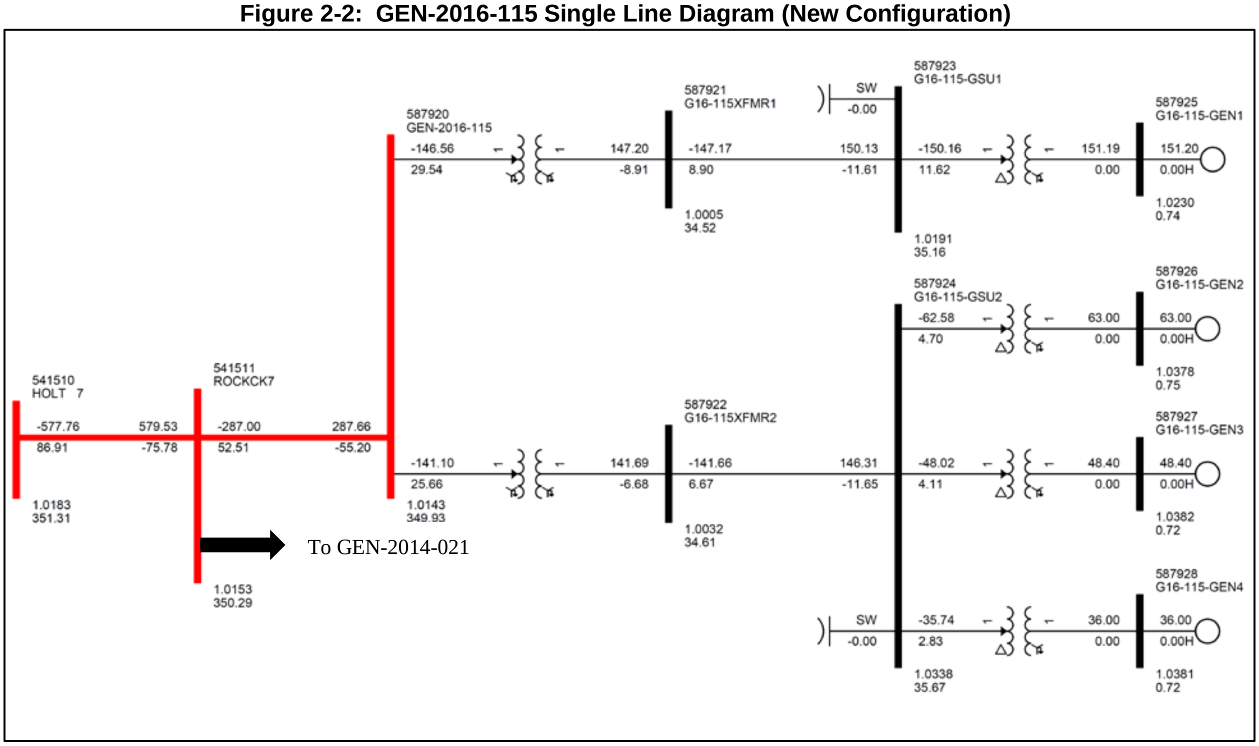


Table 2-1: GEN-2016-115 Modification Request

Facility	Existing	Modification Request			
Point of Interconnection	Holt County 345 kV switching station (541510)	Holt County 345 kV switching station (541510)			
Configuration/Capacity	150 x Vestas V110 2.0 MW = 300 MW	36 x Vestas V150 4.2 MW (Gen 1) + 15 x Vestas V150 4.2 MW (Gen 2) + 22 x Vestas V120 2.2 MW (Gen 3) + 18 x Vestas V110 2.0 MW (Gen 4) = 298.6 MW			
Generation Interconnection Line	Length = 14.6 miles	GEN-2016-115 generator substation – GEN-2014-021 generator substation = 12.44 miles		GEN-2014-021 generator substation - POI = 15.25 miles	
	R = 0.001450 pu	R = 0.000794 pu		R = 0.000536 pu	
	X = 0.009300 pu	X = 0.006197 pu		X = 0.007515 pu	
	B = 0.098440 pu	B = 0.076013 pu		B = 0.13245 pu	
Main Substation Transformer	Z = 11.1%, Winding 192 MVA, Rating 320 MVA	Transformer 1:		Transformer 2:	
		Z = 9.5%, Winding 100 MVA Rating 167 MVA		Z = 9.5%, Winding 100 MVA Rating 167 MVA	
GSU Transformer	Equivalent Qty: 150	Gen 1 Equivalent Qty: 36:	Gen 2 Equivalent Qty: 15:	Gen 3 Equivalent Qty: 22:	Gen 4 Equivalent Qty: 18:
	Z = 7.8%, Rating 315 MVA	Z = 9.9%, Rating 185.4 MVA	Z = 9.9%, Rating 77.3 MVA	Z = 9.6%, Rating 50.6 MVA	Z = 9.8%, Rating 41.4 MVA
Equivalent Collector Line	Equivalent Collector Line:	Equivalent Collector Line 1:	Equivalent Collector Line 2:		
	R = 0.002410 pu	R = 0.013568 pu	R = 0.023152 pu		
	X = 0.003860 pu	X = 0.014070 pu	X = 0.023852 pu		
	B = 0.224040 pu	B = 0.056629 pu	B = 0.094058 pu		
Reactive Power Devices	N/A	Capacitor 1:		Capacitor 2:	
		1 x 20 MVAR 34.5 kV Capacitor Bank		1 x 44 MVAR 34.5 kV Capacitor Bank	

In addition to the changes made to GEN-2016-115, per the request of the Interconnection Customer, the power flow model for GEN-2014-021 was also updated using the data provided by the Interconnection Customer. For this GEN-2016-115 MRIS, the updated Vestas V110-2.0MW Mk10C user-written Vestas Generic Model Structure V7 with the PPC module was used as the stability model for GEN-2014-021 in place of the existing stability model in the DISIS-2016-002 Group 13 package.

GEN-2014-021, which is Rock Creek wind farm, power flow model is developed based on customer provided MOD-026 model as described in RCW_MOD2627.pdf. Rock Creek wind farm is modeled as 150 Vestas V110 2.0MW wind turbines split into two lumped generators, one of which is a combination of 76 turbines while another one of which is a combination of 74 turbines.

3.0 Reactive Power Analysis

The reactive power analysis, also known as the low-wind/no-wind condition analysis, was performed for GEN-2016-115 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

The higher queued project GEN-2014-021 was first modeled with GEN-2016-115 offline. Then the GEN-2014-021 generators were switched out of service while other collector system elements remained in-service. A shunt reactor was tested at the GEN-2014-021 34.5kV buses of the generator substation to set the MVAr flow into the POI to approximately zero. Then for the GEN-2016-115 project, the generator was switched out of service while other collector system elements remained in-service. A shunt reactor was tested at the 34.5kV buses of the collection substation to set the MVAr flow into the POI to approximately zero.

3.2 Results

The results from the reactive power analysis showed that the GEN-2016-115 projects required approximately 22.9 MVAr shunt reactance at the low side of the project substation, to reduce the POI MVAr to zero. This represents the contributions from the project collection system and generator lead line.

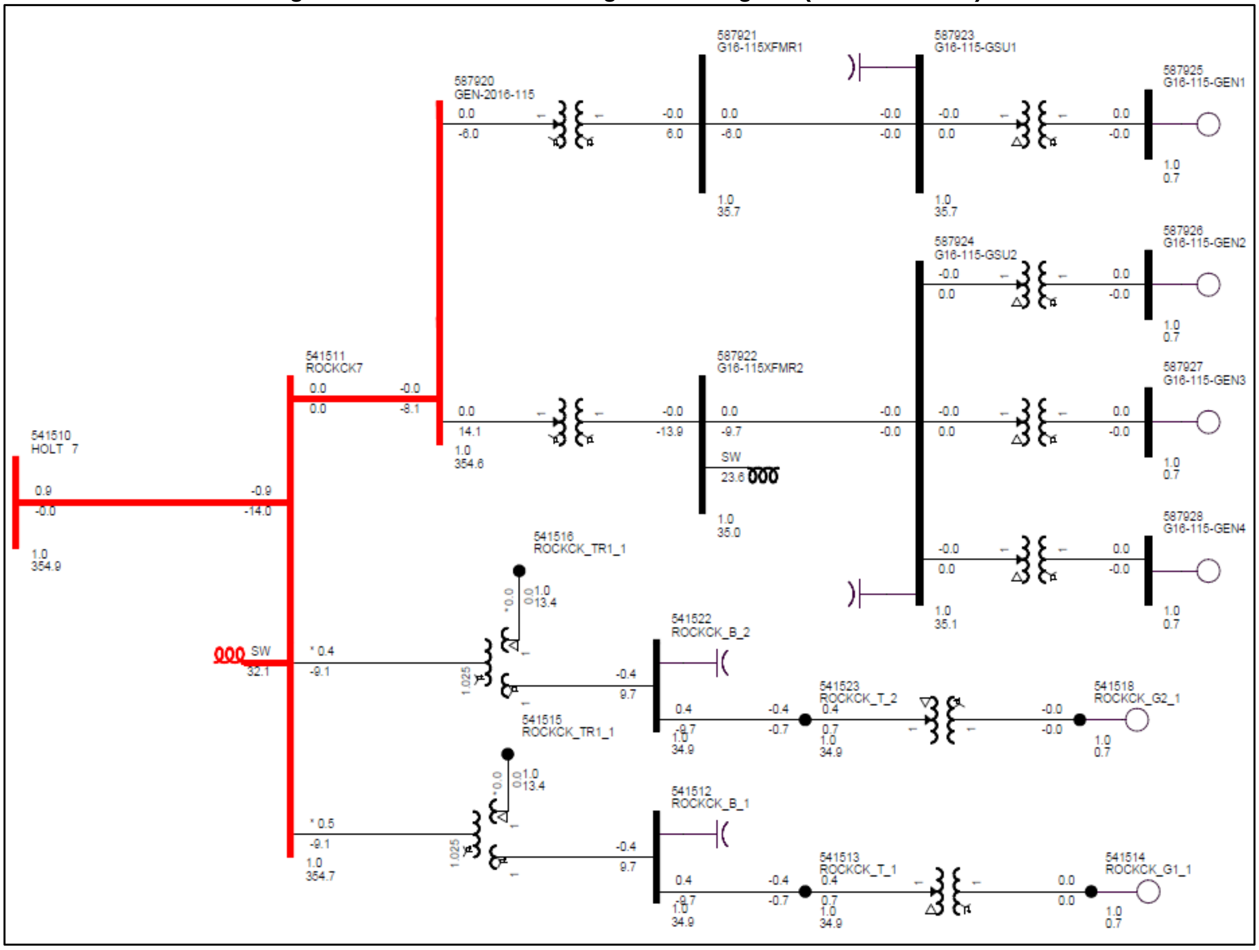
Figure 3-1 illustrates the shunt reactor size required to reduce the POI MVAr to approximately zero. Reactive compensation can be provided either by discrete reactive devices or by the generator itself if it possesses that capability.

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)		
			17WP	18SP	26SP
GEN-2016-115	541510	Transource's Rock Creek 345 kV substation	22.9	22.9	22.9

Figure 3-1: GEN-2016-115 Single Line Diagram (Shunt Reactor)



4.0 Short Circuit Analysis

A short-circuit study was performed using the 2018SP and 2026SP models for GEN-2016-115. 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 for the 2018SP and 2026SP models are summarized in Table 4-1 and Table 4-2 respectively. The maximum increase in fault current was about 4.3%, 0.26 kA. The maximum fault current calculated within 5 buses with GEN-2016-115 was less than 43 kA for the 2018SP and 2026SP models respectively.

Table 4-1: 2018SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	32.5	-0.01	0.0%
115	31.6	-0.01	0.0%
161	42.0	0.00	0.0%
345	31.3	0.26	4.3%
Max	**42.0**	**0.26**	**4.3%**

Table 4-2: 2026SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	32.6	-0.01	0.0%
115	32.1	-0.01	0.0%
161	42.2	0.00	0.0%
345	31.7	0.26	4.3%
Max	**42.2**	**0.26**	**4.3%**

5.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine configuration change and other modifications to the GEN-2016-115 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 18 Vestas V110-2.0 MW Mk10C, 22 Vestas V120-2.2 MW, and 51 Vestas V150-4.2 MW turbine configuration for the GEN-2016-115 generating facilities. This stability analysis was performed using PTI's PSS/E version 33.7 software with the customer provided user-written Vestas Generic Model Structure V7. Also note that GEN-2014-021, which also interconnects at Transource's Holt 345 kV substation, was also modeled using the Vestas V110-2.0MW Mk10C user-written Vestas Generic Model Structure V7 to incorporate the power plant controllers and control the voltage at the point of interconnection.

The stability models were developed using the models from DISIS-2016-002 for Group 13. The modifications requested to project GEN-2016-115 were used to create modified stability models for this impact study.

The modified dynamics model data for the DISIS-2016-002 Group 13 request, GEN-2016-115 is provided in Appendix C. 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-2016-115 and other equally and prior queued projects in Group 13. In addition, voltages of five (5) buses away from the POI of GEN-2016-115 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 536 (WERE), 540 (GMO), 541(KCPL), 542 (KACY), 544 (EMDE), 545 (INDN), 635 (MEC), 640 (NPPD), 645 (OPPD), 650 (LES), 652 (WAPA), 330 (AECI), and 356 (AMMO) 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 a subset of the fault events simulated specifically for GEN-2016-115 in the DISIS-2016-002 Group 13 study and includes additional faults as required. The new set of faults were simulated using the modified study models. The fault events include 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 5-1 below. These contingencies were applied to the modified 2017 Winter Peak, 2018 Summer Peak, and the 2026 Summer Peak models.

Table 5-1: Fault Definitions

Fault ID	Fault Descriptions
FLT17-3PH	3 phase fault on the KETCHEM (541500) to MULCLNCR (541197) 345kV line circuit 1, near KETCHEM. a. Apply fault at the KETCHEM 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.
FLT18-3PH	3 phase fault on the KETCHEM (541500) to SIBLEY (541201) 345kV line circuit 1, near KETCHEM. a. Apply fault at the KETCHEM 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.
FLT19-3PH	3 phase fault on the MULCLNCR (541197) to HOLT (541510) 345kV line circuit 1, near MULCLNCR. a. Apply fault at the MULCLNCR 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.
FLT20-3PH	3 phase fault on the HOLT (541510) to S3458 (645458) 345kV line circuit 1, near HOLT. a. Apply fault at the HOLT 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.
FLT21-3PH	3 phase fault on the HOLT (541510) to ROCKCK (541511) 345kV line circuit 1, near HOLT. a. Apply fault at the HOLT 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.
FLT69-3PH	3 phase fault on the ST JOE (541199) to FAIRPORT (300039) 345kV line circuit 1, near ST JOE. a. Apply fault at the ST JOE 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.
FLT70-3PH	3 phase fault on the ST JOE (541199) to COOPER (640139) 345kV line circuit 1, near ST JOE. a. Apply fault at the ST JOE 345kV bus. b. Clear fault after 4.5 cycles and trip the faulted line.
FLT72-3PH	3 phase fault on the COOPER (640139) to FAIRPORT (300039) 345kV line circuit 1, near COOPER. a. Apply fault at COOPER 345kV bus. b. Clear fault after 4.5 cycles and trip the faulted line.
FLT73-3PH	3 phase fault on the COOPER (640139) to ATCHSN (635017) 345kV line circuit 1, near COOPER. a. Apply fault at COOPER 345kV bus. b. Clear fault after 4.5 cycles and trip the faulted line.

Table 5-1 continued

Fault ID	Fault Descriptions
FLT74-3PH	3 phase fault on the COOPER (640139) to S3458 (645458) 345kV line circuit 1, near COOPER. a. Apply fault at COOPER 345kV bus. b. Clear fault after 4.5 cycles and trip the faulted line.
FLT75-3PH	3 phase fault on the COOPER (640139) to MOORE (640277) 345kV line circuit 1, near COOPER. a. Apply fault at COOPER 345kV bus. b. Clear fault after 4.5 cycles and trip the faulted line.
FLT9001-3PH	3 phase fault on the COOPER 3 (640139) 345kV to COOPER 1G (640009) 22kV transformer circuit 1, near COOPER 3. a. Apply fault at the COOPER 3 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9002-3PH	3 phase fault on the HOLT (541510) to MULLNCR7 (541197) 345kV line circuit 1, near HOLT. a. Apply fault at the HOLT 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.
FLT9005-3PH	3 phase fault on the MULLNCR7 (541197) 345kV to MC REAC3 (541413) 345kV line circuit Z1, near MULLNCR7. a. Apply fault at the MULLNCR7 345kV bus. b. Clear fault after 5 cycles and trip the reactor buses 541411,541412,541413 .
FLT9006-3PH	3 phase fault on the MULLNCR7 (541197) 345kV to KETCHEM7 (541500) 345kV line circuit 1, near MULLNCR7. a. Apply fault at the MULLNCR7 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.
FLT9007-3PH	3 phase fault on the KETCHEM7 (541500) 345kV to GEN2016-088 (587730) 345kV line circuit 1, near KETCHEM7. a. Apply fault at the KETCHEM7 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.
FLT9008-3PH	3 phase fault on the KETCHEM7 (541500) 345kV to OSBORN (541501) 345kV line circuit 1, near KETCHEM7. a. Apply fault at the KETCHEM7 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.
FLT9009-3PH	3 phase fault on the ROCKCK7 (541511) 345kV to ROCKCK (541512) 34.5kV to ROCKCK (541515) 13.2kV transformer circuit 1, near ROCKCK7 345kV. a. Apply fault at the ROCKCK7 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer and generator.
FLT9010-3PH	3 phase fault on the S3458 (645458) 345kV to S3740 (645456) 345kV line circuit 1, near S3458. a. Apply fault at the S3458 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.
FLT9011-3PH	3 phase fault on the S3458 (645458) 345kV to S3456 (645740) 345kV line circuit 1, near S3458. a. Apply fault at the S3458 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 5-1 continued

Fault ID	Fault Descriptions
FLT9012-3PH	3 phase fault on the S3458 (645458) 345kV to COOPER (640139) 345kV line circuit 1, near S3458. a. Apply fault at the S3458 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.
FLT9013-3PH	3 phase fault on the S3458 (645458) 345kV to 103&ROKEBY (650189) 345kV line circuit 1, near S3458. a. Apply fault at the S3458 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.
FLT9014-3PH	3 phase fault on the S3458 (645458) 345kV to NEBCTY2G (645012) 23kV transformer circuit 1, near S3458. a. Apply fault at the S3458 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9015-3PH	3 phase fault on the S3458 (645458) 345kV to NEBCTY1G (645011) 23kV transformer circuit 1, near S3458. a. Apply fault at the S3458 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9016-3PH	3 phase fault on the S3456 (645456) 345kV to CBLUFFS3 (635000) 345kV line circuit 1, near S3456. a. Apply fault at the S3456 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.
FLT9017-3PH	3 phase fault on the S3456 (645456) 345kV to S3459 (645459) 345kV line circuit 1, near S3456. a. Apply fault at the S3456 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.
FLT9018-3PH	3 phase fault on the S3456 (645456) 345kV to S1206 (646206) 161kV to S3456T49 (648256) 13.8kV transformer circuit 1, near S3456 345kV. a. Apply fault at the S3456 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9019-3PH	3 phase fault on the S3456 (645456) 345kV to S3455 (645455) 345kV line circuit 1, near S3456. a. Apply fault at the S3456 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.
FLT9020-3PH	3 phase fault on the S3740 (645740) 345kV to S3455 (645455) 345kV line circuit 1, near S3740. a. Apply fault at the S3740 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	3 phase fault on the COOPER (640139) 345kV to ST JOE (541199) 345kV line circuit 1, near COOPER. a. Apply fault at the COOPER 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	3 phase fault on the COOPER (640139) 345kV to COOPER (640140) 161kV to COOPER (643172) 13.8kV transformer circuit 1, near COOPER 345kV. a. Apply fault at the COOPER 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.

Table 5-1 continued

Fault ID	Fault Descriptions
FLT9024-3PH	3 phase fault on the 103&ROKEBY (650189) 345kV to WAGENER (650185) 345kV line circuit 1, near 103&ROKEBY. a. Apply fault at the 103&ROKEBY 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.
FLT22-PO1	Prior Outage of HOLT (541510) 345kV to S3458 (645458) 345kV; 3 phase fault on the SIBLEY (541201) to OVERTON (345408) 345kV line circuit 1, near SIBLEY. a. Apply fault at the SIBLEY 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.
FLT23-PO1	Prior Outage of HOLT (541510) 345kV to S3458 (645458) 345kV; 3 phase fault on the SIBLEY (541201) to PHILL (541200) 345kV line circuit 1, near SIBLEY. a. Apply fault at the SIBLEY 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.
FLT24-PO1	Prior Outage of HOLT (541510) 345kV to S3458 (645458) 345kV; 3 phase fault on the SIBLEY (541201) to HAWTH (542972) 345kV line circuit 1, near SIBLEY. a. Apply fault at the SIBLEY 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.
FLT25-PO1	Prior Outage of HOLT (541510) 345kV to S3458 (645458) 345kV; 3 phase fault on the SIBLEY 345/161/13.8kV (541201/541202/541360) transformer, near SIBLEY. a. Apply fault at the SIBLEY 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9009-PO2	Prior Outage of HOLT (541510) 345kV to MULLNCR (541197) 345kV; 3 phase fault on the ROCKCK7 (541511) 345kV to ROCKCK (541512) 34.5kV to ROCKCK (541515) 13.2kV line circuit 1 transformer, near ROCKCK7 345kV. a. Apply fault at the ROCKCK7 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9010-PO2	Prior Outage of HOLT (541510) 345kV to MULLNCR (541197) 345kV; 3 phase fault on the S3458 (645458) 345kV to S3740 (645456) 345kV line circuit 1, near S3458. a. Apply fault at the S3458 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.
FLT9011-PO2	Prior Outage of HOLT (541510) 345kV to MULLNCR (541197) 345kV; 3 phase fault on the S3458 (645458) 345kV to S3456 (645740) 345kV line circuit 1, near S3458. a. Apply fault at the S3458 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.
FLT9012-PO2	Prior Outage of HOLT (541510) 345kV to MULLNCR (541197) 345kV; 3 phase fault on the S3458 (645458) 345kV to COOPER (640139) 345kV line circuit 1, near S3458. a. Apply fault at the S3458 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.
FLT9013-PO2	Prior Outage of HOLT (541510) 345kV to MULLNCR (541197) 345kV; 3 phase fault on the S3458 (645458) 345kV to 103&ROKEBY (650189) 345kV line circuit 1, near S3458. a. Apply fault at the S3458 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 5-1 continued

Fault ID	Fault Descriptions
FLT9014-PO2	Prior Outage of HOLT (541510) 345kV to MULLNCR (541197) 345kV; 3 phase fault on the S3458 (645458) 345kV to NEBCTY2G (645012) 23kV transformer circuit 1, near S3458. a. Apply fault at the S3458 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9015-PO2	Prior Outage of HOLT (541510) 345kV to MULLNCR (541197) 345kV; 3 phase fault on the S3458 (645458) 345kV to NEBCTY1G (645011) 23kV transformer circuit 1, near S3458. a. Apply fault at the S3458 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT1001-SB	Stuck Breaker at MULLNCR (541197) a. Apply single phase fault at MULLNCR (541197) 345 kV bus. b. Clear fault after 16 cycles and trip the following elements. c. MULLNCR (541197) – HOLT (541510) 345 kV circuit 1 line. d. MULLNCR (541197) – KETCHEM7 (541500) 345 kV circuit 1 line.
FLT1003-SB	Stuck Breaker at S3458 (645458) a. Apply single phase fault at S3458 (645458) 345 kV bus. b. Clear fault after 16 cycles and trip the following elements. c. S3458 (645458) – HOLT (541510) 345 kV circuit 1 line. d. S3458 (645458) – COOPER (640139) 345 kV circuit 1 line.

5.3 Modeling Details

Based on the Interconnection Customer provided model for GEN-2016-115, the GEN-2016-115 Power Plant Controller (PPC) model was set to regulate the Rock Creek 345 kV bus voltage. Similarly, the GEN-2014-021 PPC was set to regulate the Holt 345 kV bus voltage.

In order to determine the need for the PPC for either the GEN-2016-115 or GEN-2014-021, three simulations were performed with FLT20-3PH (Nebraska City to Holt 345 kV) as shown in Table 5-2. The results showed that the PPC would be required for both GEN-2016-115 and GEN-2014-021.

Table 5-2: Plant Power Controller Scenarios

Simulation	GEN-2016-115 PPC	GEN-2014-021 PPC	FLT20 Results
Simulation 1	OFF	OFF	Unstable
Simulation 2	ON	OFF	Unstable
Simulation 3	ON	ON	Stable

Figure 5-1: GEN-2016-115 Simulation 1 Power Plot

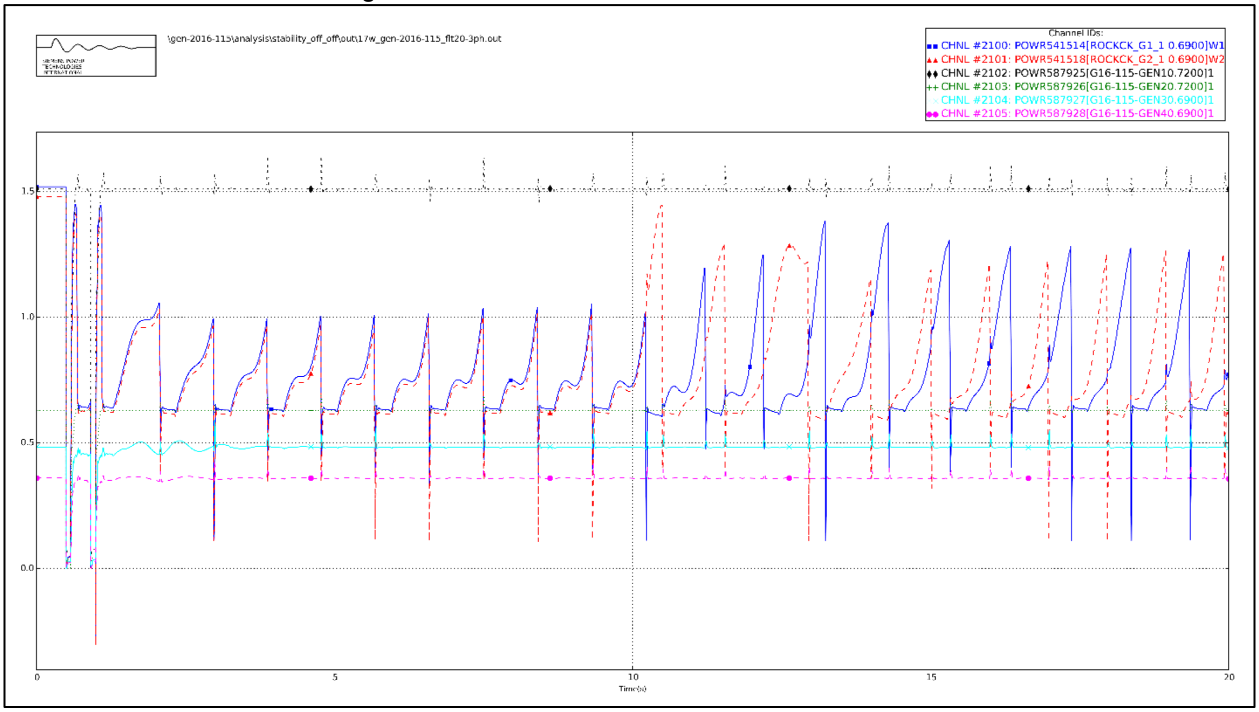


Figure 5-2: GEN-2016-115 Simulation 2 Power Plot

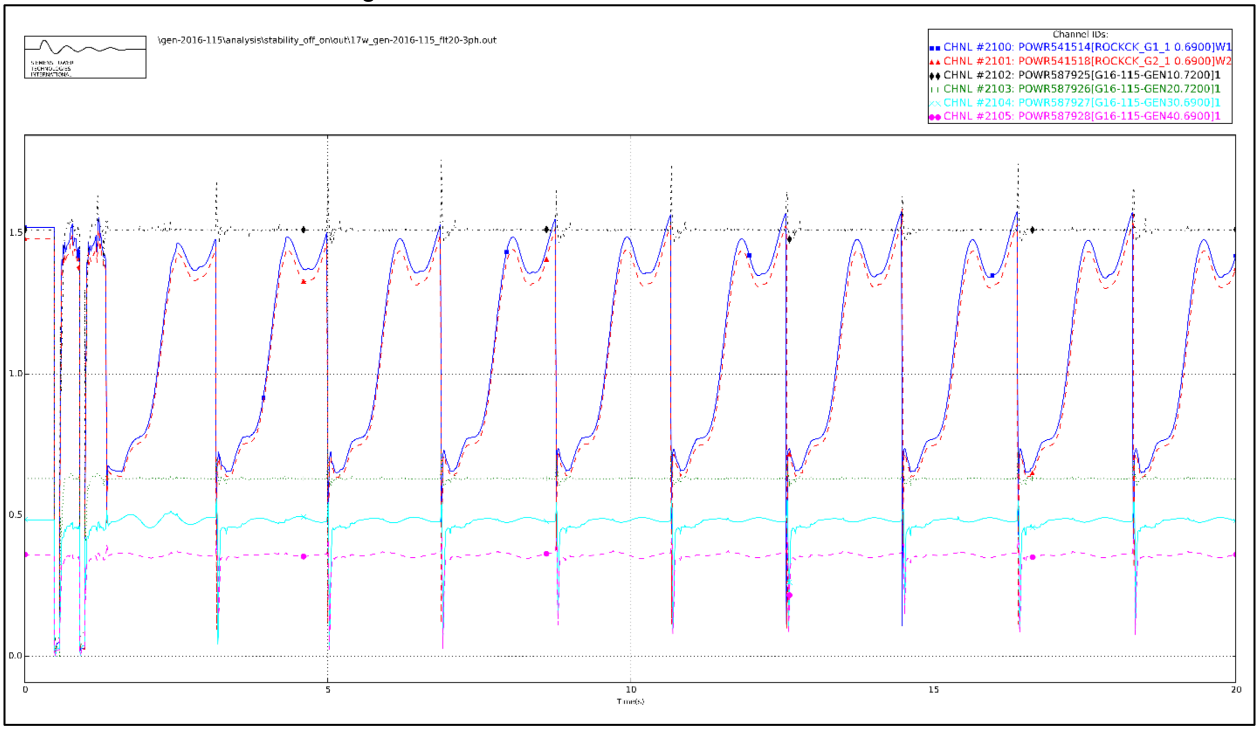
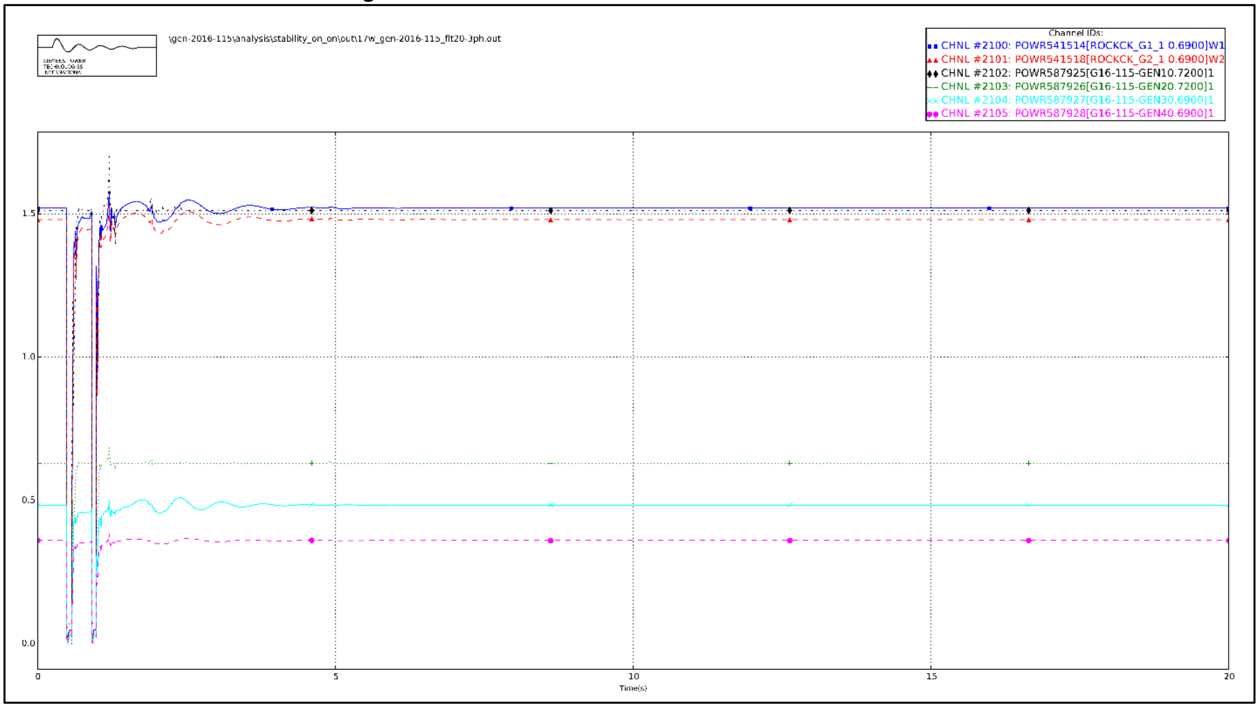


Figure 5-3: GEN-2016-115 Simulation 3 Power Plot

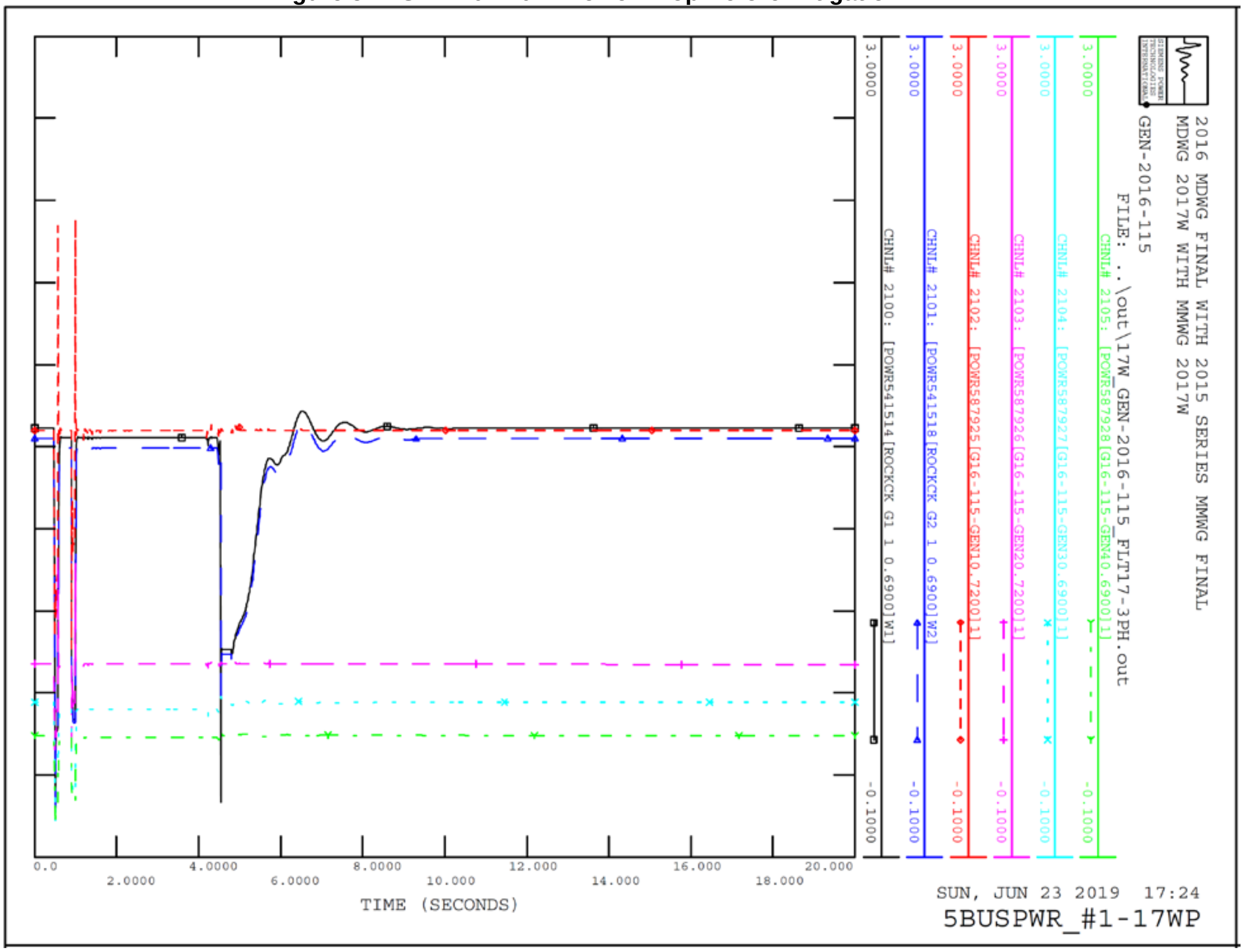


5.4 Results

Table 5-4 shows the results of the fault events simulated for each of the models. The associated stability plots are provided in Appendix D.

The results showed that during some of the fault conditions, such as FLT17, the output power of GEN-2014-021, which is also connected to the same POI as GEN-2016-115, drops several seconds after the fault has been cleared. Figure 5-4 shows that the two GEN-2014-021 units with the power drop are the equivalent units for the 2.0 MW turbines.

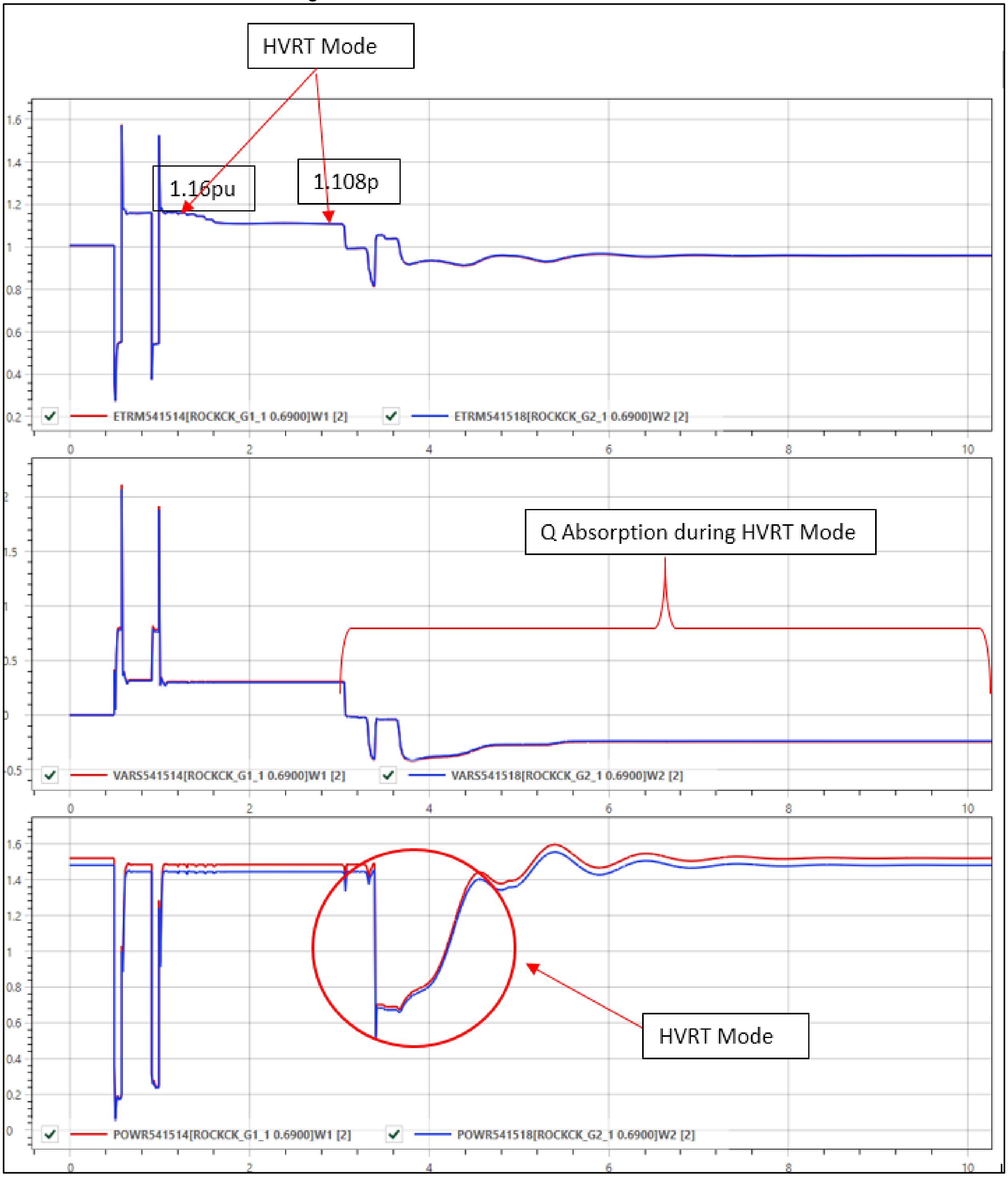
Figure 5-4: GEN-2014-021 Power Drop Before Mitigation



This turbine power response was communicated with the manufacturer, Vestas, who identified the cause of the power dip as being associated with the wind turbine generator's (WTG) dynamic model High Voltage Right Through (HVRT) exit voltage parameter (VC18084500 CON J+12). CON (J+12) parameter in the WTG is the voltage value at WTG terminal (0.69kV) at which the turbine exits HVRT Mode. Another parameter *RTPitchRiseLevelIn* is the voltage value at WTG terminal (0.69kV) at which the turbine enters HVRT Mode. While in HVRT mode, the WTG absorbs reactive current.

During the second fault applied after reclosing, the WTG terminal voltage rose to 1.16 pu, entering the HVRT mode (*RTPitchRiseLevelIn* was set to 1.15pu) but the voltage did not settle quick enoughso it remained at HVRT Mode for a while. Figure 5-5 shows the WTG terminal voltage at 1.108pu (*RTPitchRiseLevelOut* was set to 1.10 pu), just before the power dip. As a result, the WTG absorbed reactive current/power as shown by the reactive power response on the first graph in Figure 5-5. By increasing the threshold value of HVRT exit voltage (*RTPitchRiseLevelOut*) from 1.10 pu to 1.11pu, the WTG was able to exit the HVRT mode quicker to settle to pre-fault condition.

Figure 5-5: GEN-2014-021 HVRT Performance[1]



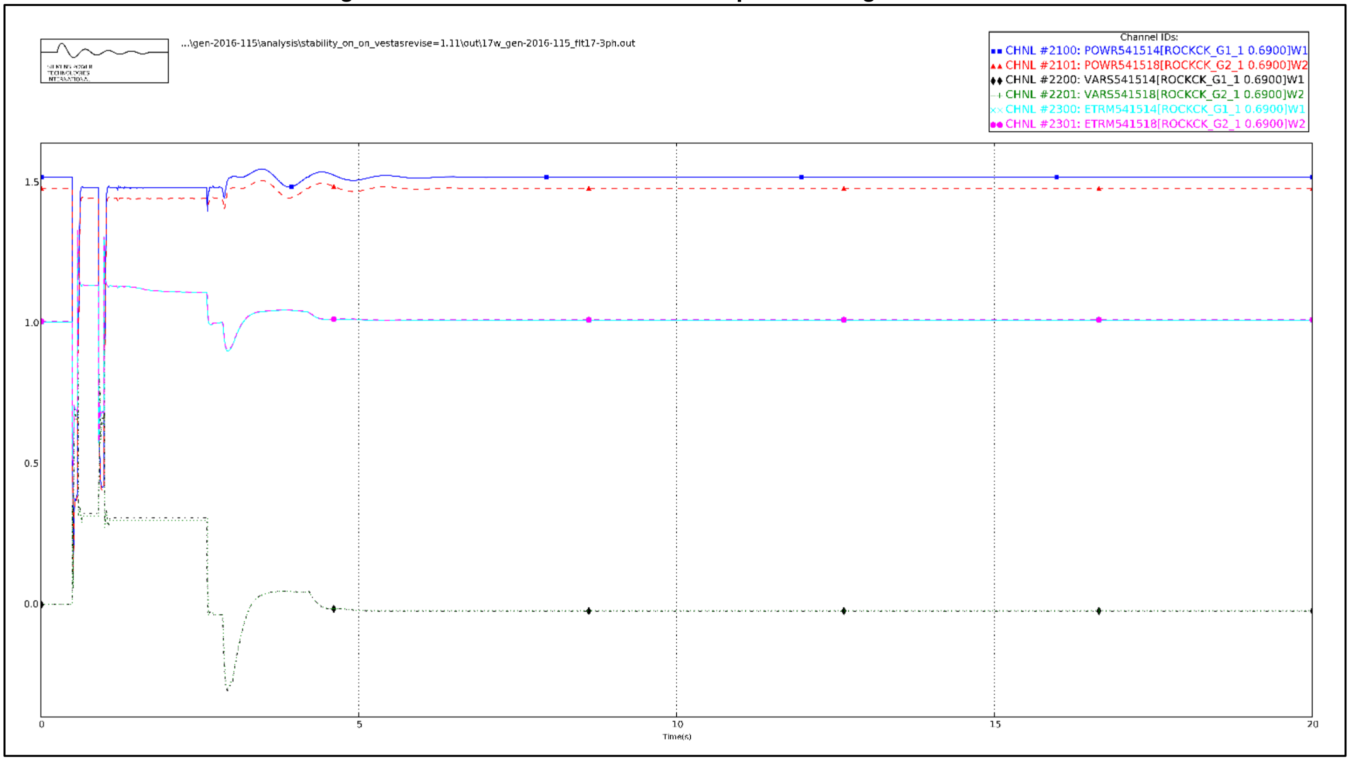
[1] Vestas provided HVRT plot for 2.0 MW turbine performance

Table 5-3: Turbine

WTG Parameter	Description	Default	Adjusted	Remarks
VC18084500 CON J+12	RTPitchRiseLevelOut	1.10pu	1.11pu	Needed to make WTGs exit HVRT Mode.

Figure 5-6 shows the power response of the GEN-2014-021 during the same fault FLT17 with the HVRT exit voltage changed to 1.11 pu.

Figure 5-6: GEN-2014-021 Power Drop After Mitigation



All the faults were simulated with the *RTPitchRiseLevelOut* change to 1.11 pu and there were no other damping or voltage recovery violations observed during the simulated faults. 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 are shown in Table 5-4 below.

The adjusted dynamic model data used to produce the final results presented in Table 5-4 can be found in Appendix B.

Table 5-4: GEN-2016-115 Dynamic Stability Results

Fault ID	17W	18S	26S
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
FLT69-3PH	Stable	Stable	Stable
FLT70-3PH	Stable	Stable	Stable
FLT72-3PH	Stable	Stable	Stable
FLT73-3PH	Stable	Stable	Stable
FLT74-3PH	Stable	Stable	Stable
FLT75-3PH	Stable	Stable	Stable
FLT9001-3PH	Stable	Stable	Stable
FLT9002-3PH	Stable	Stable	Stable
FLT9005-3PH	Stable	Stable	Stable
FLT9006-3PH	Stable	Stable	Stable
FLT9007-3PH	Stable	Stable	Stable
FLT9008-3PH	Stable	Stable	Stable
FLT9009-3PH	Stable	Stable	Stable
FLT9010-3PH	Stable	Stable	Stable
FLT9011-3PH	Stable	Stable	Stable
FLT9012-3PH	Stable	Stable	Stable
FLT9013-3PH	Stable	Stable	Stable
FLT9014-3PH	Stable	Stable	Stable
FLT9015-3PH	Stable	Stable	Stable
FLT9016-3PH	Stable	Stable	Stable
FLT9017-3PH	Stable	Stable	Stable
FLT9018-3PH	Stable	Stable	Stable
FLT9019-3PH	Stable	Stable	Stable
FLT9020-3PH	Stable	Stable	Stable
FLT9021-3PH	Stable	Stable	Stable
FLT9022-3PH	Stable	Stable	Stable
FLT9023-3PH	Stable	Stable	Stable
FLT9024-3PH	Stable	Stable	Stable
FLT1001-SB	Stable	Stable	Stable
FLT1003-SB	Stable	Stable	Stable
FLT22-PO1	Stable	Stable	Stable
FLT23-PO1	Stable	Stable	Stable

6.0 Conclusions

The Interconnection Customer for GEN-2016-115 requested a Modification Request Impact Study to assess the impact of the turbine and facility changes to a configuration with a total of 36 x Vestas V150 4.2 MW (Gen 1) + 15 x Vestas V150 4.2 MW (Gen 2) + 22 x Vestas V120 2.2 MW (Gen 3) + 18 x Vestas V110 2.0 MW (Gen 4) wind turbines for a total capacity of 298.6 MW. In addition, the modification request included changes to the collection system, generator substation transformer, and generation interconnection line.

A power factor analysis was not performed as there was no change in the point of interconnection for GEN-2016-115.

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-2016-115 project may require 22.9 MVAr of shunt reactors on the 34.5kV buses 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-2016-115 was approximately 0.26 kA for the 2018SP and 2026SP cases respectively. All three-phase current levels with the GEN-2016-115 generator online were below 43 kA for the 2018SP models and 2026SP models.

The results of the dynamic stability analysis showed that with both GEN-2014-021 and GEN-2016-115 generating facilities installing Power Plant Controllers to maintain the voltages at the Holt 345 kV bus and the Rock Creek 345 kV bus respectively, there was no violation associated with the GEN-2016-115 modification. Additionally, the project wind farm was found to stay connected during the other 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-2016-115 Modification Request, with both GEN-2014-021 and GEN-2016-115 generating facilities installing Power Plant Controllers as modeled, does not constitute a material modification.