GEN-2003-006A

Impact Restudy for Generator Modification

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REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
05/29/2020	SPP	Initial report issued.

CONTENTS

SUMMARY

The GEN-2003-006A Interconnection Customer has requested a modification to its 201 MW Interconnection Request. The modification request included removal of the STATCOM devices from the 34.5 kV collection bus and the evaluation includes updates to the collection system, main substation transformers and GSU transformers. The point of interconnection (POI) for GEN-2003-006A remains at the Elm Creek 230kV Substation.

A system impact restudy was performed by Aneden Consulting to determine whether the requested modification is a Material Modification. A Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later Queue priority date. Dynamic stability analysis, low-wind/no-wind condition analysis and impedance analysis was performed for this modification request. The full study report follows this executive summary.

The results of the dynamic stability analysis showed that with the STATCOM devices disabled a combination of the loss of the Elm Creek to North Manhattan 230 kV line and a loss of the Elm Creek 345/230/13.8 kV transformer would cause GEN-2003-006A to become unstable. This fault event, FLT1004-SB, resulted in the Elm Creek wind generating facility radially connecting through the Elm Creek to Concordia 230kV circuit and Concordia 230/115 kV transformer. This fault event was not analyzed in the previous SPP studies for GEN-2003-006A due to system configuration differences.

Sensitivity cases were run for this fault event. The results indicate that with the existing generating facility topology, a stable system response may be achieved without the STATCOM devices by adjusting the facility reactive power set point and transformer taps. The retirement of the STATCOM devices does not cause a new instability.

With the modification configuration changes, a post-event stable simulation at full output was achieved with a unity power factor by initializing the facility capacitor banks at 36 MVAR prior to the event. Alternately, setting the generator power factor to 0.99 or 0.98 lagging (providing vars) and with the capacitor banks offline prior to the event also resulted in a stable simulation.

A Vestas WTG PSS/E model with a dynamic reactive power control response, not available with the VWCOR4 user-written model, may provide a portion of the necessary dynamically controlled reactive power without requiring the PSS/E user to implement a specific pre-event reactive power set point. A newer version of the Vestas user-written model may be available that provides this enhanced functionality and should be provided to SPP for future studies.

Given the results of the impact analysis, the requested modification is not considered a Material Modification; the requested modification does not have a material impact on the cost or timing of any Interconnection Request with a later Queue priority date. There is no system

reliability concerns as a stable system response may be achieved without the STATCOM devices by adjusting the facility reactive power set point and transformer taps.

The generating facility will be required to maintain a 95% lagging (providing VARs) and 95% leading (absorbing VArs) at the POI in accordance with Appendix G of the LGIA. Additionally, the project will be required to install approximately 9.6 MVArs of reactor shunts shunt reactor on the 34.5 kV buses of the project substation, which is increased from 4.4 MVAr (existing configuration), 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.

It should be noted that this study analyzed the requested modification to change generator technology and layout. Power flow analysis was not performed. In real-time operation, 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.

In addition, 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.

Submitted to
Southwest Power Pool

SPP Southwest Power Pool

Report On

GEN-2003-006A Modification Request Impact Study

Revision R1

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Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2003-006A, an active generation interconnection request with a point of interconnection (POI) at the Elm Creek 230 kV Substation.

The GEN-2003-006A project is a Generating Facility interconnected in the Sunflower Electric Power Corporation (SUNC) control area with a capacity of 201 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2003-006A, which has a turbine configuration of 67 x Vestas V-90 3.0MW wind turbines, to remove the STATCOM devices from the 34.5 kV collection buses. In addition, the modification request evaluated updates to the collection system, main substation transformers, and GSU transformers. The modification request updates are shown in Table ES-2 below.

Table ES-1: GEN-2003-006A Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2003-006A	201	67 x Vestas V-90 3.0MW = 201 MW	Elm Creek 230 kV (539639)

Table ES-2: GEN-2003-006A Modification Request

Facility	Existing		Modification	
Point of Interconnection	Elm Creek 230 kV (539639)		Elm Creek 230 kV (539639)	
Configuration/Capacity	67 x Vestas V-90 3.0MW = 201 MW		67 x Vestas V-90 3.0MW = 201 MW	
Generation Interconnection Line	Length = 5.1 miles R = 0.000870 pu X = 0.003760 pu B = 0.014000 pu	Length = 10.5 miles R = 0.002470 pu X = 0.007300 pu B = 0.030000 pu	Length = 5.1 miles R = 0.000870 pu X = 0.003760 pu B = 0.014000 pu	Length = 10.5 miles R = 0.002470 pu X = 0.007300 pu B = 0.030000 pu
Main Substation Transformer	Z12 = 13.4%, Z23 = 26.4%, Z13 = 11.3%, Winding 100 MVA, Rating 110 MVA	Z12 = 13.4%, Z23 = 26.4%, Z13 = 11.3%, Winding 100 MVA, Rating 110 MVA	Z12 = 8.04%, Z23 = 26.4%, Z13 = 11.3%, Winding 115 MVA, Rating 115 MVA	Z12 = 8.04%, Z23 = 26.4%, Z13 = 11.3%, Winding 115 MVA, Rating 115 MVA
GSU Transformer	Gen 1 Equivalent Qty: 34: Z = 9.72%, Winding 106.76 MVA, Rating 102 MVA	Gen 2 Equivalent Qty: 33: Z = 9.72%, Winding 103.62 MVA, Rating 99 MVA	Gen 1 Equivalent Qty: 35: Z = 9.5%, Rating 110.6 MVA	Gen 2 Equivalent Qty: 32: Z = 9.5%, Rating 101.12 MVA
Equivalent Collector Line	R = 0.001000 pu X = 0.007260 pu B = 0.000000 pu	R = 0.009000 pu X = 0.013000 pu B = 0.000000 pu	R = 0.005177 pu X = 0.012488 pu B = 0.027584 pu	R = 0.005554 pu X = 0.009250 pu B = 0.023973 pu
Reactive Power Devices	4 MVAR 34.5 kV STATCOM 3 X 6 MVAR 34.5 kV Capacitor Bank	4 MVAR 34.5 kV STATCOM 3 X 6 MVAR 34.5 kV Capacitor Bank	3 X 6 MVAR 34.5 kV Capacitor Bank	3 X 6 MVAR 34.5 kV Capacitor Bank

Aneden performed reactive power, short circuit, and dynamic stability analyses using the modification request data on the initial DISIS-2016-002 Group 4 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-2003-006A.

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-2003-006A project may require a 9.6 MVAr (updated configuration) shunt reactor on the 34.5 kV buses of the project substation which is increased from 4.4 MVAr (existing configuration) 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 the short circuit analysis with the updated topology showed that the maximum GEN-2003-006A contribution to three-phase fault currents in the immediate systems at or near GEN-2003-006A was approximately 1.15 kA for the 2018SP and 2026SP cases. All three-phase fault current levels, within 5 buses of the POI, with the GEN-2003-006A generator online were below 26 kA for the 2018SP models and 2026SP models.

The dynamic stability analysis was performed using the three DISIS-2016-002 seasonal models 2017 Winter Peak, 2018 Summer Peak, 2026 Summer Peak. Up to 82 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, with the STATCOM devices disabled, a combination of the loss of the Elm Creek to North Manhattan 230 kV line and a loss of the Elm Creek 345/230/13.8 kV transformer would cause GEN-2003-006A to become unstable in the 17WP case. This fault event resulted in the Elm Creek generating facility radially connecting through the Elm Creek to Concordia 230kV circuit and Concordia 230/115 kV transformer. This fault event was not analyzed in the Customer provided study[1].

Sensitivity cases were run for this fault event (FLT1004-SB) as summarized below in Table ES-3.

Table ES-3: GEN-2003-006A FLT1004-SB Sensitivity Case Summary

Scenario	GEN-2003-006A Configuration	STATCOM Status	Capacitors Initial Status	Reactive Equipment MVAR Contribution	GEN-2003-006A PF	MPT/GSU Tap Setting Changes	FLT1004-SB Response	Report Figure Reference
S1	Modification	Offline	12 MVAR	12 MVAR	1	No	Unstable	5-1
S2	Modification	Offline	24 MVAR	24 MVAR	1	No	Unstable	5-2
S3	Modification	Offline	36 MVAR	36 MVAR	1	No	Stable	5-3
S4	Modification	Offline	0 MVAR	0 MVAR	0.99 Lagging	No	Stable	5-4
S5	Modification	Offline	0 MVAR	0 MVAR	0.98 Lagging	No	Stable	5-5
S6	Existing	Offline	36 MVAR	36 MVAR	1	No	Unstable	5-6
S7	Existing	Offline	0 MVAR	0 MVAR	0.98 Lagging	No	Unstable	5-7
S8A	Existing	Offline	36 MVAR	36 MVAR	0.98 Lagging	No	Gen Trips	5-8
S8	Existing	Offline	36 MVAR	36 MVAR	0.98 Lagging	Yes	Stable	5-9
S9	Existing	Online	36 MVAR	44 MVAR	1	No	Unstable	5-10
S10A	Existing	Online	36 MVAR	44 MVAR	0.99 Lagging	No	Gen Trips	5-11
S10	Existing	Online	36 MVAR	44 MVAR	0.99 Lagging	Yes	Stable	5-12

[1] Meridian Way Wind Farm Reactive Compensation Study (GEN-2003-006A) Report

With the modification configuration changes, a post-event stable simulation at full output was achieved with a unity (1.0) power factor by initializing the facility capacitor banks at 36 MVAR prior to the event (S3). Alternately, setting the generator power factor to 0.99 or 0.98 lagging (providing vars) and with the capacitor banks offline prior to the event also resulted in a stable simulation (S4 & S5).

With the existing GEN-2003-006A configuration, a stable simulation was achieved with the STATCOM devices switched offline, the capacitor banks set to 36 MVAR, the GEN-2003-006A generator power factor set to 0.98, and the transformer tap points adjusted to avoid high voltage tripping (S8). With the existing configuration and the STATCOM devices switched online, a stable output was found when the capacitor banks were set to 36 MVAR, the GEN-2003-006A generator power factor was set to 0.99, and the transformer tap points were adjusted to avoid high voltage tripping (S10). Scenario 8 and 10 show that a stable response can be achieved if the capacitor banks are dispatched at 36 MVAR, the generator power factor is at least 0.99, and the transformer tap points are adjusted regardless of the STATCOM status. The retirement of the STATCOM devices does not cause a new instability.

A Vestas WTG PSS/E model with a dynamic reactive power control response, not available with the VWCOR4 user-written model, may provide a portion of the necessary dynamically controlled reactive power without requiring the PSS/E user to implement a specific pre-event reactive power set point. A newer version of the Vestas user-written model may be available that provides this enhanced functionality and should be provided to SPP for future studies.

There were no other machine rotor angle damping or transient voltage recovery violations observed in the simulated fault events for the generator 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.

1.0 Introduction

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2003-006A, an active generation interconnection request with a point of interconnection (POI) at the Elm Creek 230 Substation.

The GEN-2003-006A project is a Generating Facility interconnected in the Sunflower Electric Power Corporation (SUNC) control area with a combined capacity of 201 MW as shown in Table 1-1 below. Details of the modification request is provided in Section 2.0 below.

Table 1-1: Existing GEN-2003-006A Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2003-006A	201	67 x Vestas V-90 3.0MW = 201 MW	Elm Creek 230 kV (539639)

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 completed using a set of modified study models developed using the modification request data and the three 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.

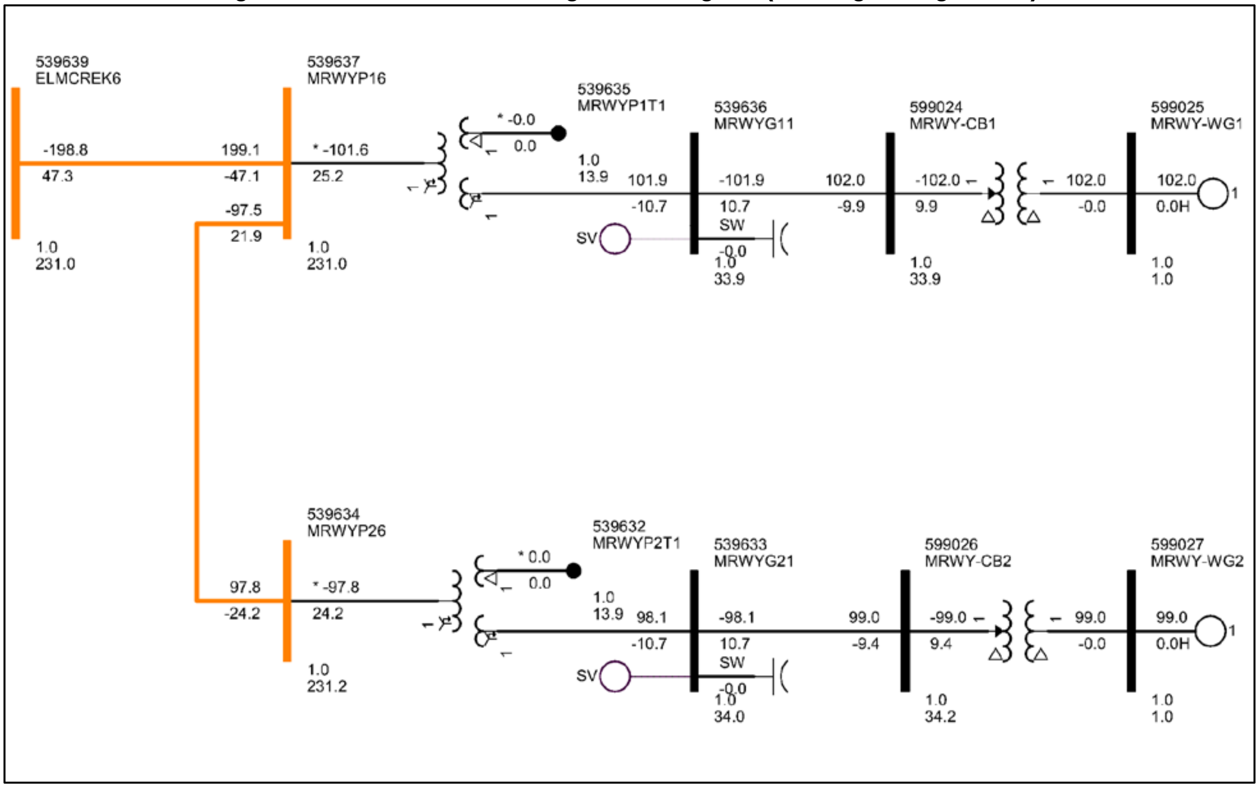
1.2 Study Limitations

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

GEN-2003-006A was originally studied in an impact study completed in September of 2007[2]. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2003-006A configuration modeled in the DISIS-2016-002 models.

Figure 2-1: GEN-2003-006A Single Line Diagram (Existing Configuration)



The GEN-2003-006A Modification Request did not change the existing turbine configuration of 67 x Vestas V-90 3.0MW wind turbines with total capacity of 201 MW. The modification request altered the existing configuration by removing the STATCOM devices at the 34.5 kV collection buses. In addition, the modification request also evaluated updates to the collection system, main substation transformers, and GSU transformers. The major modification request updates are shown in Figure 2-2 and Table 2-1 below.

[2] Impact Study For Generation Interconnection Request GEN-2003-006A posted in September of 2007

Figure 2-2: GEN-2003-006A Single Line Diagram (New Configuration)

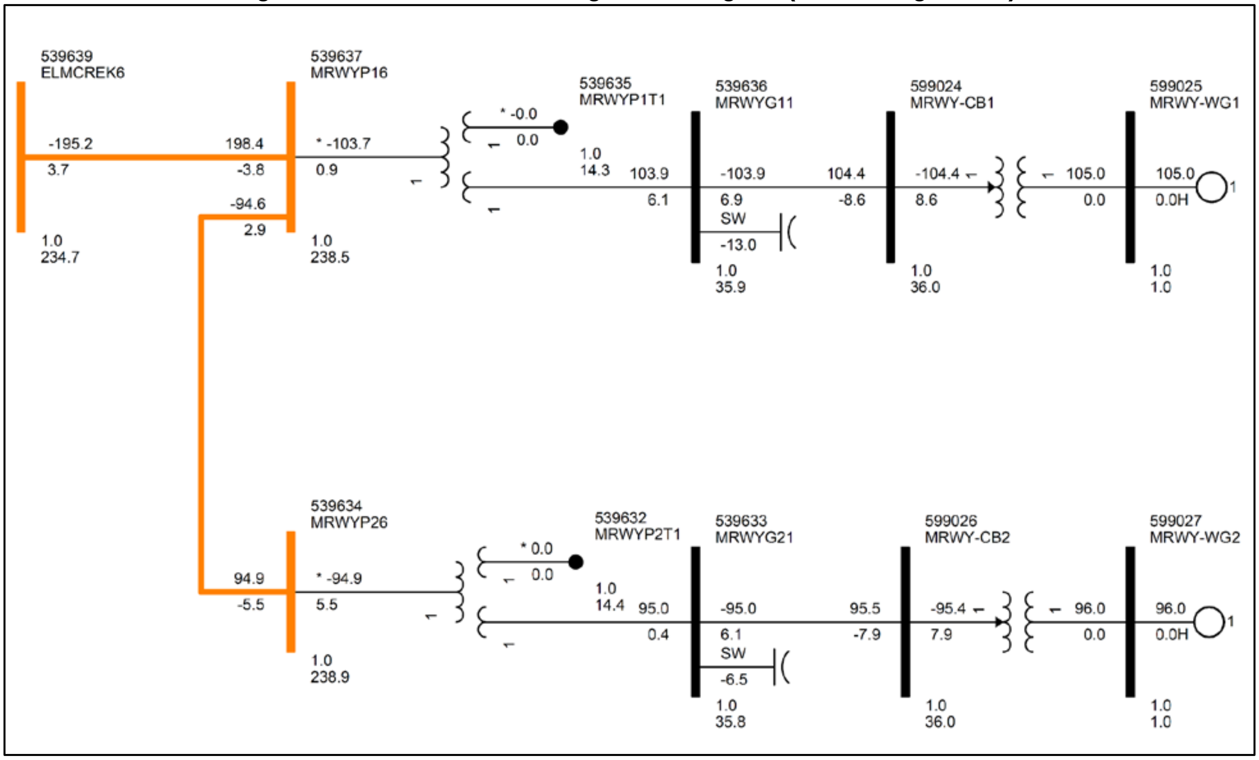


Table 2-1: GEN-2003-006A Modification Request

Facility	Existing		Modification	
Point of Interconnection	Elm Creek 230 kV (539639)		Elm Creek 230 kV (539639)	
Configuration/Capacity	67 x Vestas V-90 3.0MW = 201 MW		67 x Vestas V-90 3.0MW = 201 MW	
Generation Interconnection Line	Length = 5.1 miles R = 0.000870 pu X = 0.003760 pu B = 0.014000 pu	Length = 10.5 miles R = 0.0024700 pu X = 0.007300 pu B = 0.030000 pu	Length = 5.1 miles R = 0.000870 pu X = 0.003760 pu B = 0.014000 pu	Length = 10.5 miles R = 0.0024700 pu X = 0.007300 pu B = 0.030000 pu
Main Substation Transformer	Z12 = 13.4%, Z23 = 26.4%, Z13 = 11.3%, Winding 100 MVA, Rating 110 MVA	Z12 = 13.4%, Z23 = 26.4%, Z13 = 11.3%, Winding 100 MVA, Rating 110 MVA	Z12 = 8.04%, Z23 = 26.4%, Z13 = 11.3%, Winding 115 MVA, Rating 115 MVA	Z12 = 8.04%, Z23 = 26.4%, Z13 = 11.3%, Winding 115 MVA, Rating 115 MVA
GSU Transformer	Gen 1 Equivalent Qty: 34: Z = 9.72%, Winding 106.76 MVA, Rating 102 MVA	Gen 2 Equivalent Qty: 33: Z = 9.72%, Winding 103.62 MVA, Rating 99 MVA	Gen 1 Equivalent Qty: 35: Z = 9.5%, Rating 110.6 MVA	Gen 2 Equivalent Qty: 32: Z = 9.5%, Rating 101.12 MVA
Equivalent Collector Line	R = 0.001000 pu X = 0.007260 pu B = 0.000000 pu	R = 0.009000 pu X = 0.013000 pu B = 0.000000 pu	R = 0.005177 pu X = 0.012488 pu B = 0.027584 pu	R = 0.005554 pu X = 0.009250 pu B = 0.023973 pu
Reactive Power Devices	4 MVAR 34.5 kV STATCOM 3 X 6 MVAR 34.5 kV Capacitor Bank	4 MVAR 34.5 kV STATCOM 3 X 6 MVAR 34.5 kV Capacitor Bank	3 X 6 MVAR 34.5 kV Capacitor Bank	3 X 6 MVAR 34.5 kV Capacitor Bank

3.0 Reactive Power Analysis

The reactive power analysis, also known as the low-wind/no-wind condition analysis, was performed for GEN-2003-006A 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-2003-006A project, the generators and reactive power devices were switched out of service while other collector system elements remained in-service. A shunt reactor was tested at the collection substation 34.5 kV bus 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-2003-006A project required an approximately 9.6 MVAr (updated configuration) shunt reactor at the project substation, to reduce the POI MVAr to zero which increased from 4.4 MVAr (existing configuration). Figure 3-1 illustrates the shunt reactor size required to reduce the POI MVAr to approximately zero with the existing project configuration. Figure 3-2 illustrates the shunt reactor size required to reduce the POI MVAr to approximately zero with the updated project configuration. Reactive compensation can be provided either by discrete reactive devices or by the generator itself if it possesses that capability.

Figure 3-1: Existing GEN-2003-006A Single Line Diagram (Shunt Reactor)

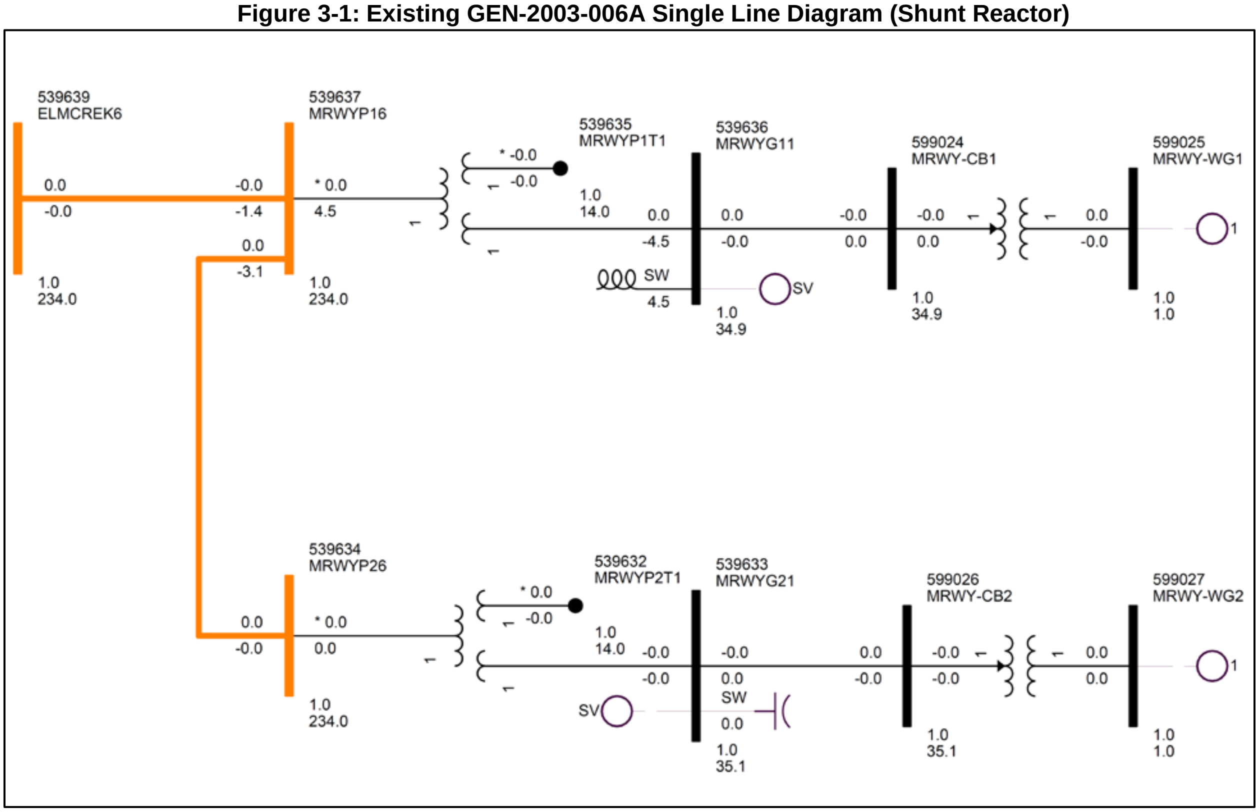


Figure 3-2: Modified GEN-2003-006A Single Line Diagram (Shunt Reactor)

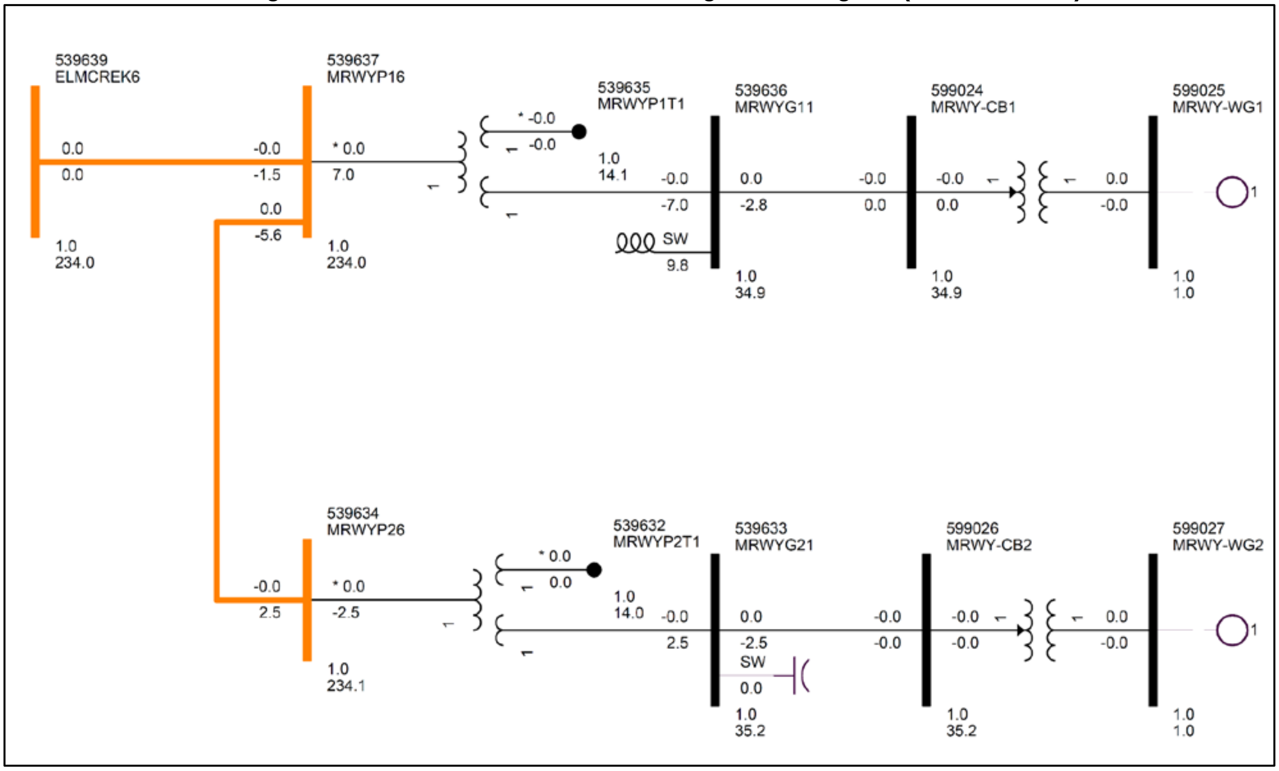


Table 3-1 shows the shunt reactor size determined for the three modified configuration study models used in the assessment.

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

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)		
			17WP	18SP	26SP
GEN-2003-006A	539639	Elm Creek 230 kV	9.6	9.6	9.6

4.0 Short Circuit Analysis

A short-circuit study was performed using the 2018SP and 2026SP models for GEN-2003-006A with the updated topology. 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 230 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 GEN-2003-006A contribution to three-phase fault currents was about 16.8%, 1.15 kA. The maximum fault current calculated within 5 buses with GEN-2003-006A was less than 26 kA for the 2018SP and 2026SP models respectively. The maximum change of 16.8% was observed at the Elm Creek 230 kV POI bus, which had GEN-2003-006A offline and online fault levels of 6.84 and 7.99 kA respectively.

Table 4-1: 2018SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
115	21.4	0.34	4.7%
230	25.0	1.15	16.8%
345	23.8	0.55	11.0%
Max	**25.0**	**1.15**	**16.8%**

Table 4-2: 2026SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
115	21.2	0.34	4.6%
230	25.0	1.15	16.7%
345	24.0	0.55	10.9%
Max	**25.0**	**1.15**	**16.7%**

5.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of removing the STATCOM devices from the 34.5 kV collection bus in addition to evaluating updates to the configuration of the GEN-2003-006A generating facility. 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 existing 67 Vestas V-90 3.0MW turbine configuration without the STATCOM devices present for the GEN-2003-006A 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 dispatched for Group 4. The requested modification of removing the STATCOM and updating the generator facility configuration for GEN-2003-006A were used to create modified stability models for this impact study.

The modified dynamics model data for the DISIS-2016-002 Group 4 request, GEN-2003-006A 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-2003-006A and other equally and prior queued projects in Group 4. In addition, voltages of five (5) buses away from the POI of GEN-2003-006A 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), 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 simulated the faults previously simulated for GEN-2003-006A and selected additional fault events for GEN-2003-006A 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 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
F01-3PH	3 phase fault on the CONCORD3 (539657) to CLIFTON3 (539656) 115 kV line circuit 1, near CONCORD3. a. Apply fault at the CONCORD3 115 kV 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.
F02-3PH	3 phase fault on the CONCRD6 (539658) to ELMCREK6 (539639) 230 kV line circuit 1, near CONCRD6. a. Apply fault at the CONCRD6 230 kV 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.
F03-3PH	3 phase fault on the ELMCREK6 (539639) to NMANHT6 (532865) 230 kV line circuit 1, near ELMCREK6. a. Apply fault at the ELMCREK6 230 kV 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.
F04-3PH	3 phase fault on the NMANHT6 (532865) to EMANHAT6 (532861) 230 kV line circuit 1, near NMANHT6. a. Apply fault at the NMANHT6 230 kV 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.
F05-3PH	3 phase fault on the ELMCREK6 (539639) to CONCRD6 (539658) 230 kV line circuit 1, near ELMCREK6. a. Apply fault at the ELMCREK6 230 kV 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.
F06-3PH	3 phase fault on the EMANHAT6 (532861) to JEC 6 (532852) 230 kV line circuit 1, near EMANHAT6. a. Apply fault at the EMANHAT6 230 kV 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.
F07-3PH	3 phase fault on the CONCORD3 (539657) to JEWELL 3 (539669) 115 kV line circuit 1, near CONCORD3. a. Apply fault at the CONCORD3 115 kV 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.
F08-3PH	3 phase fault on the CONCORD3 (539657) to BELOIT 3 (539650) 115 kV line circuit 1, near CONCORD3. a. Apply fault at the CONCORD3 115 kV 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.
F01-SLG*	**SLG fault at Concordia on 115 kV line to Clifton, Breaker failure at Concordia (539657)** a. Apply single phase fault at the Concordia (539657) 115 kV bus. b. Wait 9 cycles c. Drop Concordia (539657) - CLIFTON3 (539656) 115kV, ckt 1 line. d. Wait 21 cycles and remove fault e. Drop SMITH-C3 (539693) – IONIA 3 (539647) 115kV, ckt 1 line. f. Drop IONIA 3 (539647) – JEWELL 3 (539669) 115kV, ckt 1 line. g. Drop SMITH-C3 (539693) – GLENELD3 (539663) 115kV, ckt 1 line. h. Drop CONCRD6 (539658) – ELMCREK6 (539639) 230 kV, ckt 1 line.
F02-SLG*	**SLG fault at Concordia on 230 kV line to Cloud Tap, Interrupter failure at Concordia (539658)** a. Apply single phase fault at the Concordia (539658) 230 kV bus. b. Wait 7 cycles c. Drop CONCRD6 (539658) – ELMCREK6 (539639) 230 kV, ckt 1 line. d. Wait 9 cycles and remove fault e. Drop SMITH-C3 (539693) – IONIA 3 (539647) 115kV, ckt 1 line. f. Drop IONIA 3 (539647) – JEWELL 3 (539669) 115kV, ckt 1 line. g. Drop SMITH-C3 (539693) – GLENELD3 (539663) 115kV, ckt 1 line. h. Drop Concordia (539657) - CLIFTON3 (539656) 115kV, ckt 1 line.

Table 5-1 continued

Fault ID	Fault Descriptions
F03-SLG*	**SLG fault at Elm Creek on 230 kV line to East Manhattan, Breaker failure at East Manhattan** a. Apply single phase fault at the Elm Creek (539639) 230 kV bus. b. Wait 5 cycles c. Drop Elm Creek (539639) – North Manhattan (532865) 230 kV, ckt 1 line. d. Wait 25 cycles and remove fault e. Drop Elm Creek (539639) – North Manhattan (532865) 230 kV, ckt 1 line. f. Drop East Manhattan (532861) – North Manhattan (532865) 230 kV, ckt 1 line. g. Drop East Manhattan (532861) – JEC (532852) 230 kV, ckt 1 line.
F04-SLG*	**SLG fault at East Manhattan on 230 kV line to Cloud Tap, Breaker failure at Elm Creek** a. Apply single phase fault at the East Manhattan (532861) 230 kV bus. b. Wait 10 cycles c. Drop Elm Creek (539639) – North Manhattan (532865) 230 kV, ckt 1 line. d. Drop East Manhattan (532861) – North Manhattan (532865) 230 kV, ckt 1 line. e. Wait 6 cycles and remove fault f. Drop CONCRD6 (539658) – ELMCREK6 (539639) 230 kV, ckt 1 line.
F05-SLG	SLG fault at Elm Creek (539639) on 230 kV line to Concordia (539658) a. Apply fault at the Elm Creek 230 kV 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.
FLT01-3PH	3 phase fault on the RENO7 (532771) to WICHITA7 (532796) 345kV line circuit 1, near RENO7. a. Apply fault at the RENO7 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.
FLT02-1PH	Single phase fault on the RENO7 (532771) to WICHITA7 (532796) 345kV line circuit 1, near RENO7. a. Apply fault at the RENO7 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.
FLT03-3PH	3 phase fault on the RENO7 (532771) to G16-111-TAP (587884) 345kV line circuit 1, near RENO7. a. Apply fault at the RENO7 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.
FLT04-1PH	Single phase fault on the RENO7 (532771) to G16-111-TAP (587884) 345kV line circuit 1, near RENO7. a. Apply fault at the RENO7 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.
FLT05-3PH	3 phase fault on the RENO7 (532771) to RENO3 (533416) to RENO 2X1 (532810) 3 Phase Transformer ID-1, near RENO7 a. Apply fault at the RENO7 345kV bus. b. Clear fault after 5 cycles by tripping the faulted Transformer
FLT06-3PH	3 phase fault on the G16-111-TAP (587884) to G16-112-TAP (587894) 345 kV line circuit 1, near G16-111-TAP. a. Apply fault at the G16-111-TAP 345 kV 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.
FLT07-1PH	Single phase fault on the G16-111-TAP (587884) to G16-112-TAP (587894) 345 kV line circuit 1, near G16-111-TAP. a. Apply fault at the G16-111-TAP 345 kV 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
FLT08-3PH	3 phase fault on the G16-112-TAP (587894) to SUMMIT 7 (532773) 345 kV line circuit 1, near G16-112-TAP. a. Apply fault at the G16-112-TAP 345 kV 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.
FLT09-1PH	Single phase fault on the G16-112-TAP (587894) to SUMMIT 7 (532773) 345 kV line circuit 1, near G16-112-TAP. a. Apply fault at the G16-112-TAP 345 kV 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.
FLT10-3PH	3 phase fault on SUMMIT 7 345 kV (532773) to SUMMIT 6 230 kV (532873) to SUMMIT 1 14.4 kV (532813) XFMR ckt 1, near SUMMIT 7 345 kV. a. Apply fault at the SUMMIT 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT1001-SB	**Concordia (539657) 115 kV Stuck Breaker Scenario 1** a. Apply single phase fault at the Concordia (539657) 115 kV bus. b. Wait 16 cycles and remove fault. c. Drop Concordia (539657) - Beloit (539650) 115kV, ckt 1 line. d. Drop Concordia 230/115/13.8kV Transformer (539658) (539657)(539904) "1".
FLT1002-SB	**Concordia (539657) 115 kV Stuck Breaker Scenario 2** a. Apply single phase fault at the Concordia (539657) 115 kV bus. b. Wait 16 cycles and remove fault. c. Drop Concordia 230/115/13.8kV Transformer (539658) (539657)(539904) "1". d. Drop Concordia 115/34.5/5.11 kV Transformer (539657) (539705)(539905) "1". e. Drop Concordia 115/34.5/7.2 kV Transformer (539657) (539745)(539945) "1".
FLT1003-SB	**Concordia (539658) 230kV Stuck Breaker Scenario 1** a. Apply single phase fault at the Concordia (539658) 230 kV bus. b. Wait 16 cycles and remove fault. c. Drop Concordia 230/115/13.8kV Transformer (539658) (539657) (539904) "1"
FLT1004-SB	**Elm Creek (539639) 230kV Stuck Breaker Scenario 1** a. Apply single phase fault at the Elm Creek (539639) 230 kV bus. b. Wait 16 cycles and remove fault. c. Drop Elm Creek (539639) - NMANHT6 (532865) 230kV, ckt 1 line d. Drop Elm Creek 345/230/13.8kV Transformer (539805) (539639) (539806) "1"
FLT1005-SB	**Elm Creek (539639) 230kV Stuck Breaker Scenario 2** a. Apply single phase fault at the Elm Creek (539639) 230 kV bus. b. Wait 16 cycles and remove fault. c. Drop Concordia (539658) - Elm Creek (539639) 230kV, ckt 1 line. d. Drop Elm Creek 345/230/13.8kV Transformer (539805) (539639) (539806) "1" e. Drop Elm Creek 345 kV Capacitor
FLT1006-SB	**Elm Creek (539805) 345kV Stuck Breaker Scenario 4** a. Apply single phase fault at the Elm Creek (539805) 345 kV bus. b. Wait 16 cycles and remove fault. c. Drop Elm Creek (539805) - Summit (532773) 345kV, ckt 1 line d. Drop Elm Creek 345/230/13.8kV Transformer (539805) (539639) (539806) "1"
FLT1007-SB	**Concordia (539658) 230kV Stuck Breaker Scenario 3** a. Apply single phase fault at the Concordia (539658) 230 kV bus. b. Wait 16 cycles and remove fault. c. Drop Concordia (539657) - Beloit (539650) 115kV, ckt 1 line. d. Drop Concordia 230/115/13.8kV Transformer (539658) (539657)(539904) "1"
FLT1008-SB	**North Manhattan (532865) 230kV Stuck Breaker Scenario 1** a. Apply single phase fault at the North Manhattan (532865) 230kV bus. b. Wait 16 cycles and remove fault. c. Drop Elm Creek (539639) - NMANHT6 (532865) 230kV, ckt 1 line d. Drop North Manhattan 230/115/14.4kV Transformer (532865) (533347) (532901) "1"

Table 5-1 continued

Fault ID	Fault Descriptions
FLT1009-SB	**North Manhattan (532865) 230kV Stuck Breaker Scenario 2** a. Apply single phase fault at the North Manhattan (532865) 230kV bus. b. Wait 16 cycles and remove fault. c. Drop Elm Creek (539639) - NMANHT6 (532865) 230kV, ckt 1 line d. Drop NMANHT6 (532865) - EMANHAT6 (532861) 230kV, ckt 1 line
FLT1010-SB	**North Manhattan (532865) 230kV Stuck Breaker Scenario 3** a. Apply single phase fault at the North Manhattan (532865) 230kV bus. b. Wait 16 cycles and remove fault. c. Drop NMANHT6 (532865) - EMANHAT6 (532861) 230kV, ckt 1 line d. Drop North Manhattan 230/115/14.4kV Transformer (532865) (533347) (532901) "1"
FLT1011-SB	**Summit (532773) 345kV Stuck Breaker Scenario 1** a. Apply single phase fault at the Summit (532773) 345 kV bus. b. Wait 16 cycles and remove fault. c. Drop Summit (532773) - G16-112-TAP (587894) - 345kV, ckt 1 line d. Drop Summit 345/230/14.4kV Transformer (532773) (532873) (532813) "1"
FLT1012-SB (18SP and 26SP Only)	**Summit (532773) 345kV Stuck Breaker Scenario 2** a. Apply single phase fault at the Summit (532773) 345 kV bus. b. Wait 16 cycles and remove fault. c. Drop Elm Creek (539805) - Summit (532773) 345kV, ckt 1 line d. Drop Summit (532773) - Geary (532767) 345kV, ckt 1 line
FLT1013-SB (17WP Only)	**Summit (532773) 345kV Stuck Breaker Scenario 3** a. Apply single phase fault at the Summit (532773) 345 kV bus. b. Wait 16 cycles and remove fault. c. Drop Elm Creek (539805) - Summit (532773) 345kV, ckt 1 line d. Drop Summit (532773) - JEC N 7 (532766) 345kV, ckt 1 line
FLT9001-3PH	3 phase fault on ELMCREK6 230 kV (539639) to ELMCREEK7 345 kV (539805) to ELMCREEK1 13.8 kV (539806) XFMR, near ELMCREK6 230 kV. a. Apply fault at the ELMCREK6 230 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9002-3PH	3 phase fault on the ELMCREEK7 (539805) to SUMMIT 7 (532773) 345 kV line circuit 1, near ELMCREEK7. a. Apply fault at the ELMCREEK7 345 kV 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.
FLT9003-3PH (17WP Only)	3 phase fault on the SUMMIT 7 (532773) to JEC N 7 (532766) 345 kV line circuit 1, near SUMMIT 7. a. Apply fault at the SUMMIT 7 345 kV 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.
FLT9004-3PH	3 phase fault on the SUMMIT 7 (532773) to G16-112-TAP (587894) 345 kV line circuit 1, near SUMMIT 7. a. Apply fault at the SUMMIT 7 345 kV 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.
FLT9005-3PH	3 phase fault on the SUMMIT 6 (532873) to EMCPHER6 (532872) 230 kV line circuit 1, near SUMMIT 6. a. Apply fault at the SUMMIT 6 230 kV 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	3 phase fault on the SUMMIT 6 (532873) to UNIONRG6 (532874) 230 kV line circuit 1, near SUMMIT 6. a. Apply fault at the SUMMIT 6 230 kV 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
FLT9007-3PH	3 phase fault on the SUMMIT 6 (532873) to SMOKYHL6 (530592) 230 kV line circuit 1, near SUMMIT 6. a. Apply fault at the SUMMIT 6 230 kV 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.
FLT9008-3PH	3 phase fault on NMANHT6 230 kV (532865) to NMANHT3 115 kV (533347) to NMANHX1 14.4 kV (532901) XFMR, near NMANHT6 230 kV. a. Apply fault at the NMANHT6 230 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9009-3PH	3 phase fault on the SUMMIT 3 (533381) to EXIDE J3 (533368) 115 kV line circuit 1, near SUMMIT 3. a. Apply fault at the SUMMIT 3 115 kV 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	3 phase fault on the SUMMIT 3 (533381) to NORTHVW3 (533371) 115 kV line circuit 1, near SUMMIT 3. a. Apply fault at the SUMMIT 3 115 kV 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.
FLT9011-3PH	3 phase fault on EMANHAT6 230 kV (532861) to EMANHAT3 115 kV (533326) to EMANHAT1 18 kV (532888) XFMR, near EMANHAT6 230 kV. a. Apply fault at the EMANHAT6 230 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9012-3PH	3 phase fault on CONCRD6 230 kV (539658) to CONCORD3 115 kV (539657) to CONCOD-T 13.8 kV (539904) XFMR, near CONCRD6 230 kV. a. Apply fault at the CONCRD6 230 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9013-3PH	3 phase fault on CONCORD3 115 kV (539657) to CCORDIA1 34.5 kV (539745) to CCORD-T 7.2 kV (539945) XFMR, near CONCORD3 115 kV. a. Apply fault at the CONCORD3 115 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9014-3PH	3 phase fault on CONCORD3 115 kV (539657) to CONCORD1 34.5 kV (539705) to CONCOW-T 5.11 kV (539905) XFMR, near CONCORD3 115 kV. a. Apply fault at the CONCORD3 115 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9015-3PH	3 phase fault on the JEC N 7 (532766) to MORRIS 7 (532770) 345 kV line circuit 1, near JEC N 7. a. Apply fault at the JEC N 7 345 kV 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.
FLT9016-3PH	3 phase fault on the JEC N 7 (532766) to HOYT 7 (532765) 345 kV line circuit 1, near JEC N 7. a. Apply fault at the JEC N 7 345 kV 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.
FLT9017-3PH	3 phase fault on JEC N 7 345 kV (532766) to JEC 6 230 kV (532852) to JEC 13 1 14.4 kV (532805) XFMR, near JEC N 7 345 kV. a. Apply fault at the JEC N 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.

Table 5-1 continued

Fault ID	Fault Descriptions
FLT9018-3PH	3 phase fault on the SUMMIT 3 (533381) to SO GATE3 (533379) 115 kV line circuit 1, near SUMMIT 3. a. Apply fault at the SUMMIT 3 115 kV 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.
FLT9019-3PH	3 phase fault on SUMMIT 6 230 kV (532873) to SUMMIT 3 115 kV (533381) to SUMIT2 1 13.8 kV (532896) XFMR, near SUMMIT 6 230 kV. a. Apply fault at the SUMMIT 6 230 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9020-3PH	3 phase fault on the JEC 6 (532852) to JEC U1 (532651) 230/26 kV transformer circuit 1, near JEC 6. a. Apply fault at the JEC 6 230/26 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer. Drop generator JEC U1 (532651)
FLT9021-3PH	3 phase fault on the JEC N 7 (532766) to JEC U2 (532652) 345/26 kV transformer circuit 1, near JEC N 7. a. Apply fault at the JEC N 7 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer. Drop generator JEC U2 (532652)
FLT9022-3PH	3 phase fault on the JEC N 7 (532766) to JEC U3 (532653) 345/26 kV transformer circuit 1, near JEC N 7. a. Apply fault at the JEC N 7 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer. Drop generator JEC U3 (532653)
FLT9023-3PH	3 phase fault on the JEC 6 (532852) to AUBURN 6 (532851) 230 kV line circuit 1, near JEC 6. a. Apply fault at the JEC 6 230 kV 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.
FLT9024-3PH (18SP and 26SP Only)	3 phase fault on GEARY 7 345 kV (532767) to GEARY 3 115 kV (533336) to GEARY1X1 13.8 kV (532834) XFMR, near GEARY 7 345 kV. a. Apply fault at the GEARY 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9025-3PH (18SP and 26SP Only)	3 phase fault on the SUMMIT 7 (532773) to GEARY 7 (532767) 345 kV line circuit 1, near SUMMIT 7. a. Apply fault at the SUMMIT 7 345 kV 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.
FLT9026-3PH (18SP and 26SP Only)	3 phase fault on the GEARY 7 (532767) to JEC N 7 (532766) 345 kV line circuit 1, near GEARY 7. a. Apply fault at the GEARY 7 345 kV 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.
F03-PO1	**Prior Outage of Elm Creek (539805) to Summit (532773) 345kV line and Elm Creek 345/230/13.8 kV transformer (539805/539639/539806)** 3 phase fault on the ELMCREK6 (539639) to NMANHT6 (532865) 230 kV line circuit 1, near ELMCREK6. a. Apply fault at the ELMCREK6 230 kV 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.
F03-PO2	**Prior Outage of Elm Creek (539805) to Concordia (539658) 230 kV line** 3 phase fault on the ELMCREK6 (539639) to NMANHT6 (532865) 230 kV line circuit 1, near ELMCREK6. a. Apply fault at the ELMCREK6 230 kV 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
F05-PO1	**Prior Outage of Elm Creek (539805) to Summit (532773) 345kV line and Elm Creek 345/230/13.8 kV transformer (539805/539639/539806)** 3 phase fault on the ELMCREK6 (539639) to CONCRD6 (539658) 230 kV line circuit 1, near ELMCREK6. a. Apply fault at the ELMCREK6 230 kV 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.
F05-PO3	**Prior Outage of Elm Creek (539805) to North Manhattan (532865) 230 kV line** 3 phase fault on the ELMCREK6 (539639) to CONCRD6 (539658) 230 kV line circuit 1, near ELMCREK6. a. Apply fault at the ELMCREK6 230 kV 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.
FLT9001-PO2	**Prior Outage of Elm Creek (539805) to Concordia (539658) 230 kV line** 3 phase fault on ELMCREK6 230 kV (539639) to ELMCREEK7 345 kV (539805) to ELMCREEK1 13.8 kV (539806) XFMR, near ELMCREK6 230 kV. a. Apply fault at the ELMCREK6 230 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9001-PO3	**Prior Outage of Elm Creek (539805) to North Manhattan (532865) 230 kV line** 3 phase fault on ELMCREK6 230 kV (539639) to ELMCREEK7 345 kV (539805) to ELMCREEK1 13.8 kV (539806) XFMR, near ELMCREK6 230 kV. a. Apply fault at the ELMCREK6 230 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9003-PO2 (17WP Only)	**Prior Outage of Elm Creek (539805) to Concordia (539658) 230 kV line** 3 phase fault on the SUMMIT 7 (532773) to JEC N 7 (532766) 345 kV line circuit 1, near SUMMIT 7. a. Apply fault at the SUMMIT 7 345 kV 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.
FLT9003-PO3 (17WP Only)	**Prior Outage of Elm Creek (539805) to North Manhattan (532865) 230 kV line** 3 phase fault on the SUMMIT 7 (532773) to JEC N 7 (532766) 345 kV line circuit 1, near SUMMIT 7. a. Apply fault at the SUMMIT 7 345 kV 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.
FLT9024-PO2 (18SP and 26SP Only)	**Prior Outage of Elm Creek (539805) to Concordia (539658) 230 kV line** 3 phase fault on GEARY 7 345 kV (532767) to GEARY 3 115 kV (533336) to GEARY1X1 13.8 kV (532834) XFMR, near GEARY 7 345 kV. a. Apply fault at the GEARY 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9025-PO2 (18SP and 26SP Only)	**Prior Outage of Elm Creek (539805) to Concordia (539658) 230 kV line** 3 phase fault on the SUMMIT 7 (532773) to GEARY 7 (532767) 345 kV line circuit 1, near SUMMIT 7. a. Apply fault at the SUMMIT 7 345 kV 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.
FLT9026-PO2 (18SP and 26SP Only)	**Prior Outage of Elm Creek (539805) to Concordia (539658) 230 kV line** 3 phase fault on the GEARY 7 (532767) to JEC N 7 (532766) 345 kV line circuit 1, near GEARY 7. a. Apply fault at the GEARY 7 345 kV 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.
FLT9024-PO3 (18SP and 26SP Only)	**Prior Outage of Elm Creek (539805) to North Manhattan (532865) 230 kV line** 3 phase fault on GEARY 7 345 kV (532767) to GEARY 3 115 kV (533336) to GEARY1X1 13.8 kV (532834) XFMR, near GEARY 7 345 kV. a. Apply fault at the GEARY 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.

Table 5-1 continued

Fault ID	Fault Descriptions
FLT9025-PO3 (18SP and 26SP Only)	**Prior Outage of Elm Creek (539805) to North Manhattan (532865) 230 kV line** 3 phase fault on the SUMMIT 7 (532773) to GEARY 7 (532767) 345 kV line circuit 1, near SUMMIT 7. a. Apply fault at the SUMMIT 7 345 kV 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.
FLT9026-PO3 (18SP and 26SP Only)	**Prior Outage of Elm Creek (539805) to North Manhattan (532865) 230 kV line** 3 phase fault on the GEARY 7 (532767) to JEC N 7 (532766) 345 kV line circuit 1, near GEARY 7. a. Apply fault at the GEARY 7 345 kV 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-PO2	**Prior Outage of Elm Creek (539805) to Concordia (539658) 230 kV line** 3 phase fault on the RENO7 (532771) to G16-111-TAP (587884) 345kV line circuit 1, near RENO7. a. Apply fault at the RENO7 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.
FLT06-PO2	**Prior Outage of Elm Creek (539805) to Concordia (539658) 230 kV line** 3 phase fault on the G16-111-TAP (587884) to G16-112-TAP (587894) 345 kV line circuit 1, near G16-111-TAP. a. Apply fault at the G16-111-TAP 345 kV 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-PO2	**Prior Outage of Elm Creek (539805) to Concordia (539658) 230 kV line** 3 phase fault on the G16-112-TAP (587894) to SUMMIT 7 (532773) 345 kV line circuit 1, near G16-112-TAP. a. Apply fault at the G16-112-TAP 345 kV 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-PO3	**Prior Outage of Elm Creek (539805) to North Manhattan (532865) 230 kV line** 3 phase fault on the RENO7 (532771) to G16-111-TAP (587884) 345kV line circuit 1, near RENO7. a. Apply fault at the RENO7 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.
FLT06-PO3	**Prior Outage of Elm Creek (539805) to North Manhattan (532865) 230 kV line** 3 phase fault on the G16-111-TAP (587884) to G16-112-TAP (587894) 345 kV line circuit 1, near G16-111-TAP. a. Apply fault at the G16-111-TAP 345 kV 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 Elm Creek (539805) to North Manhattan (532865) 230 kV line** 3 phase fault on the G16-112-TAP (587894) to SUMMIT 7 (532773) 345 kV line circuit 1, near G16-112-TAP. a. Apply fault at the G16-112-TAP 345 kV 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.

* These SLG faults were simulated as defined in the previous study report[3], with necessary configuration modifications. These faults may not be viable anymore due to these network changes.

[3] Impact Study For Generation Interconnection Request GEN-2003-006A posted in September of 2007

5.3 Results

Table 5-2 shows the results of the fault events simulated with the STATCOM devices disabled in each of the three modified cases. The associated stability plots are provided in Appendix D.

The results of the dynamic stability analysis showed that with the STATCOM devices disabled a combination of the loss of the Elm Creek to North Manhattan 230 kV line and a loss of the Elm Creek 345/230/13.8 kV transformer would cause GEN-2003-006A to become unstable in the 17WP case. This fault event resulted in the Elm Creek wind generating facility radially connecting through the Elm Creek to Concordia 230kV circuit and Concordia 230/115 kV transformer. The unstable response from GEN-2003-006A was also observed in the existing representation of GEN-2003-006A with the STATCOM devices enabled. This fault event was not analyzed in the Customer provided study[4]. These fault events were not analyzed in the previous SPP studies for GEN-2003-006A due to system configuration differences.

Table 5-2: GEN-2003-006A Dynamic Stability Results – STATCOM Disabled

Fault ID	17WP			18SP			26SP		
	Volt. Recovery	Volt. Violation	Stable	Volt. Recovery	Volt. Violation	Stable	Volt. Recovery	Volt. Violation	Stable
F01-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
F02-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
F03-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
F04-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
F05-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
F06-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
F07-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
F08-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
F01-SLG	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
F02-SLG	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
F03-SLG	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
F04-SLG	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
F05-SLG	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT01-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-1PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-1PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT06-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-1PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT08-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT09-1PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT10-3PH	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

[4] Meridian Way Wind Farm Reactive Compensation Study (GEN-2003-006A) Report

Table 5-2 continued – STATCOM Disabled

Fault ID	17WP			18SP			26SP		
	Volt. Recovery	Volt. Violation	Stable	Volt. Recovery	Volt. Violation	Stable	Volt. Recovery	Volt. Violation	Stable
FLT1004-SB	Pass	Fail	**Unstable***	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
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1012-SB (18SP and 26SP Only)				Pass	Pass	Stable	Pass	Pass	Stable
FLT1013-SB (17WP Only)	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 (17WP Only)	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	Pass	Pass	Stable	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
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 (18SP and 26SP Only)				Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH (18SP and 26SP Only)				Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH (18SP and 26SP Only)				Pass	Pass	Stable	Pass	Pass	Stable
F03-PO1	Pass	Pass	**Unstable***	Pass	Pass	Stable	Pass	Pass	Stable
F05-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
F03-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 5-2 continued – STATCOM Disabled

Fault ID	17WP			18SP			26SP		
	Volt. Recovery	Volt. Violation	Stable	Volt. Recovery	Volt. Violation	Stable	Volt. Recovery	Volt. Violation	Stable
FLT9003-PO2 (17WP Only)	Pass	Pass	Stable						
FLT9024-PO2 (18SP and 26SP Only)				Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-PO2 (18SP and 26SP Only)				Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-PO2 (18SP and 26SP Only)				Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT06-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT08-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
F05-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO3	Pass	Fail	**Unstable***	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO3 (17WP Only)	Pass	Pass	Stable						
FLT9024-PO3 (18SP and 26SP Only)				Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-PO3 (18SP and 26SP Only)				Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-PO3 (18SP and 26SP Only)				Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT06-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT08-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

*Instability exists in 17WP case even with STATCOM enabled

The study default settings when the GEN-2003-006A project was modeled with the user-written model resulted in an unstable simulation due to post-event low voltage. With these default settings the power factor was set to unity (1.0) and the six (6) 6 MVAR capacitor banks (36 MVAR total), located on the generating facility 34.5KV collector station buses, were offline prior to the event.

Sensitivity cases were run for this fault event (FLT1004-SB) as summarized below in Table 5-3. These results indicate that with the existing (2016 MDWG) generating facility topology, a stable system response may be achieved without the STATCOM devices by adjusting the facility reactive power set point and transformer taps. With the updated generating facility topology, a stable system response may be achieved without the STATCOM devices by adjusting the facility reactive power set point without adjusting transformer taps.

Table 5-3: GEN-2003-006A FLT1004-SB Sensitivity Case Summary

Scenario	GEN-2003-006A Configuration	STATCOM Status	Capacitors Initial Status	Total Project MVAR Contribution	GEN-2003-006A PF	MPT/GSU Tap Setting Changes	FLT1004-SB Response	Report Figure Reference
S1	Modification	Offline	12 MVAR	12 MVAR	1	No	Unstable	5-1
S2	Modification	Offline	24 MVAR	24 MVAR	1	No	Unstable	5-2
S3	Modification	Offline	36 MVAR	36 MVAR	1	No	Stable	5-3
S4	Modification	Offline	0 MVAR	28.64 MVAR	0.99 Lagging	No	Stable	5-4
S5	Modification	Offline	0 MVAR	40.81 MVAR	0.98 Lagging	No	Stable	5-5
S6	Existing	Offline	36 MVAR	36 MVAR	1	No	Unstable	5-6
S7	Existing	Offline	0 MVAR	40.81 MVAR	0.98 Lagging	No	Unstable	5-7
S8A	Existing	Offline	36 MVAR	76.81 MVAR	0.98 Lagging	No	Gen Trips	5-8
S8	Existing	Offline	36 MVAR	76.81 MVAR	0.98 Lagging	Yes	Stable	5-9
S9	Existing	Online 8 MVAR	36 MVAR	44 MVAR	1	No	Unstable	5-10
S10A	Existing	Online 8 MVAR	36 MVAR	72.64 MVAR	0.99 Lagging	No	Gen Trips	5-11
S10	Existing	Online 8 MVAR	36 MVAR	72.64 MVAR	0.99 Lagging	Yes	Stable	5-12

With the modification configuration, a post-event stable simulation at full output was achieved with a unity power factor by initializing the facility capacitor banks at 36 MVAR prior to the event as shown in Figure 5-3 (S3). Figure 5-1 and Figure 5-2 show that the system response is still unstable when only 12 or 24 MVAR are being produced by the capacitor banks (S1 & S2).

Figure 5-1: MRIS GEN-2003-006A Response to FLT1004-SB with 12 MVAR Cap (S1)

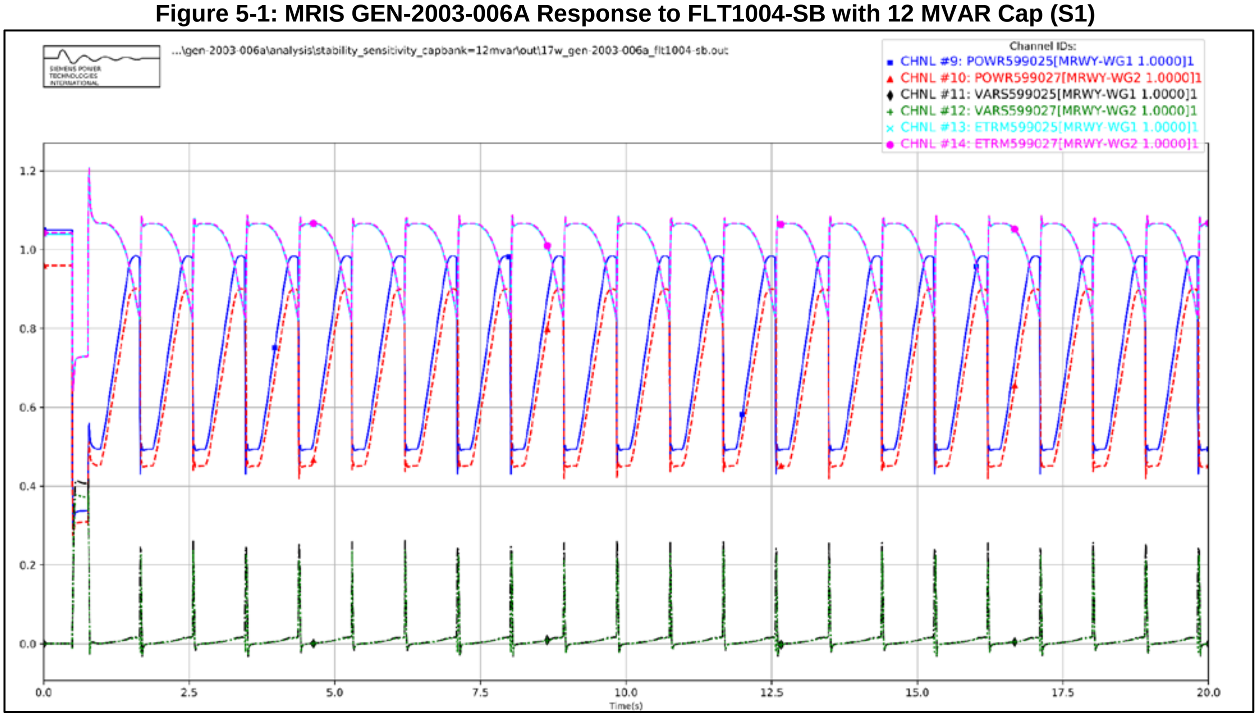


Figure 5-2: MRIS GEN-2003-006A Response to FLT1004-SB with 24 MVAR Cap (S2)

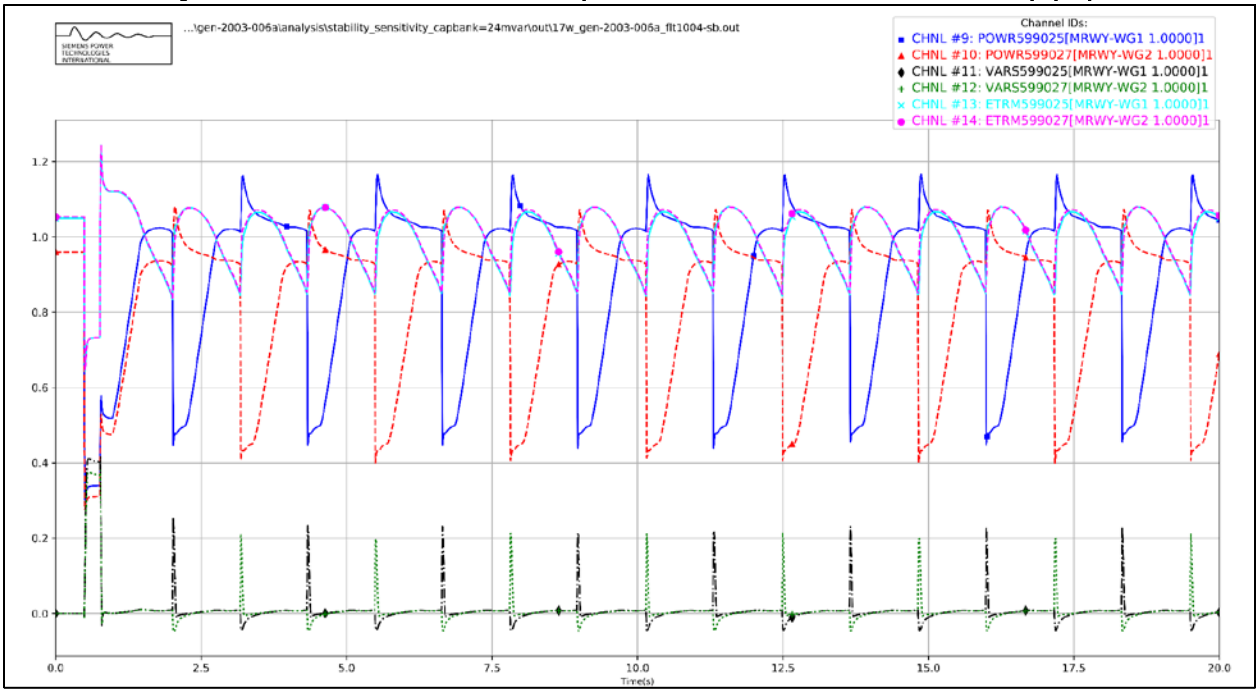
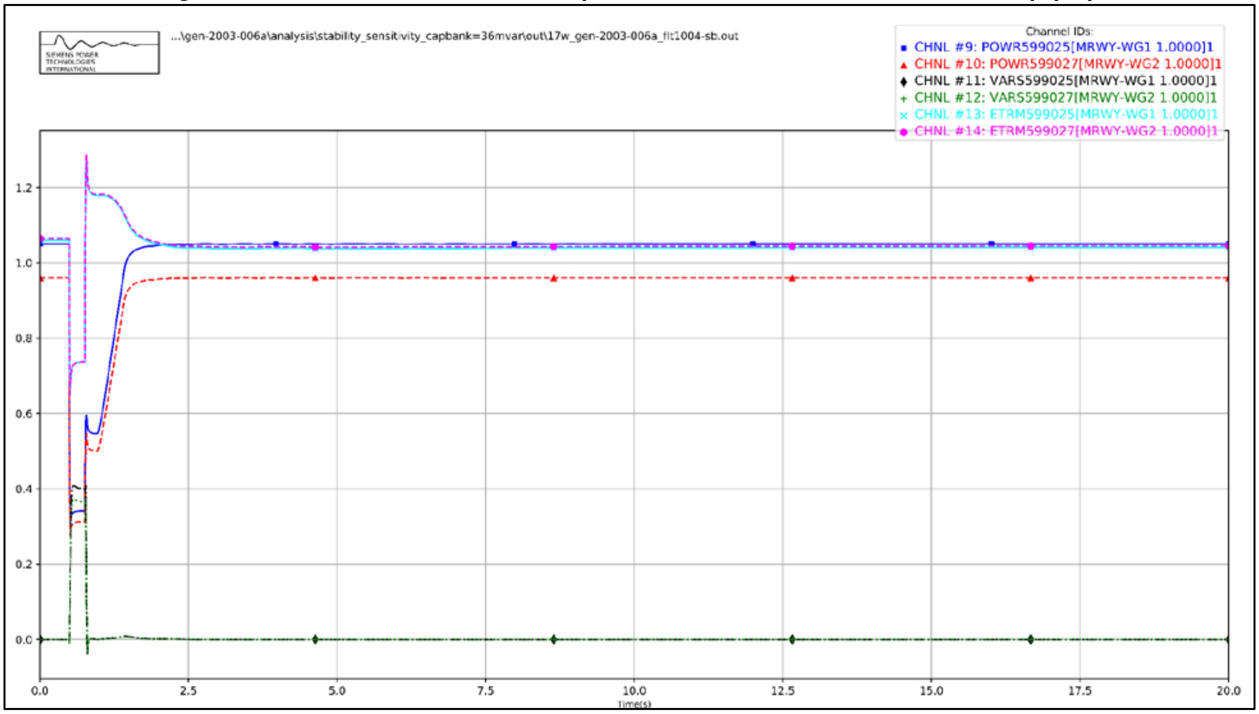


Figure 5-3: MRIS GEN-2003-006A Response to FLT1004-SB with 36 MVAR Cap (S3)



Alternately, setting the generator power factor to 0.99 or 0.98 lagging (providing vars) and with the capacitor banks offline prior to the event also resulted in a stable simulation as shown in Figure 5-4 and Figure 5-5 (S4 & S5).

Figure 5-4: MRIS GEN-2003-006A Response to FLT1004-SB with GEN PF at 0.99 (S4)

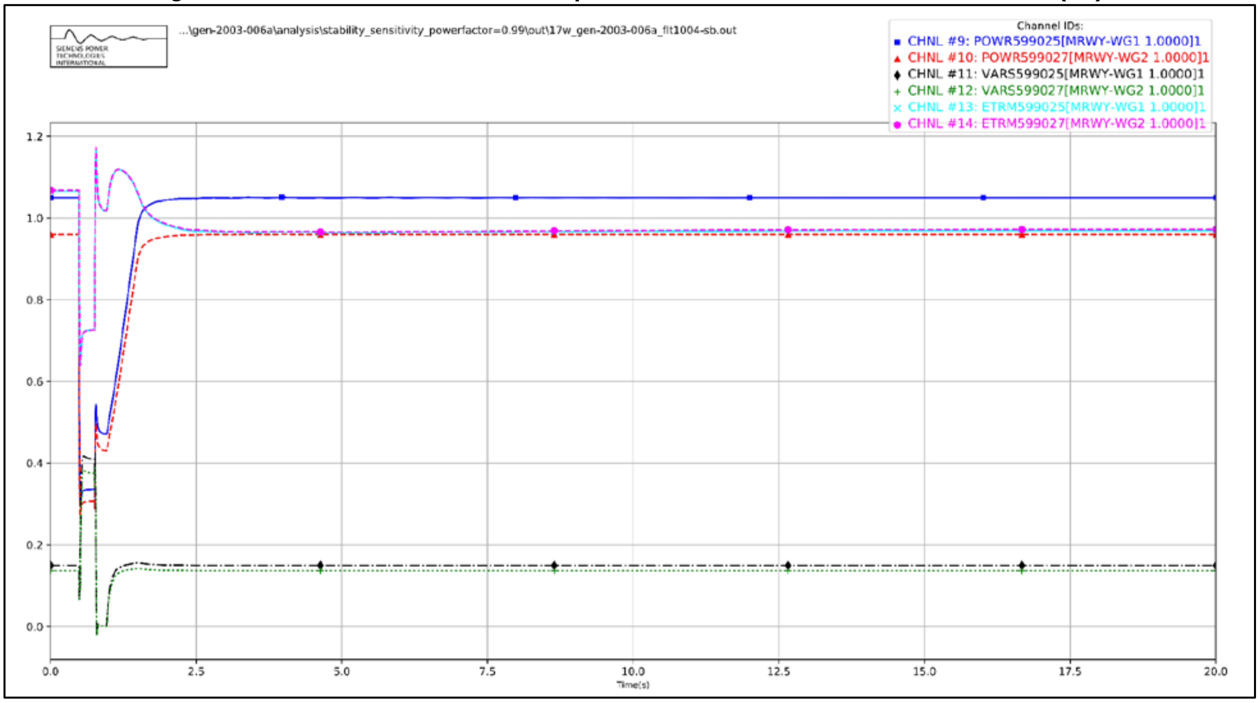
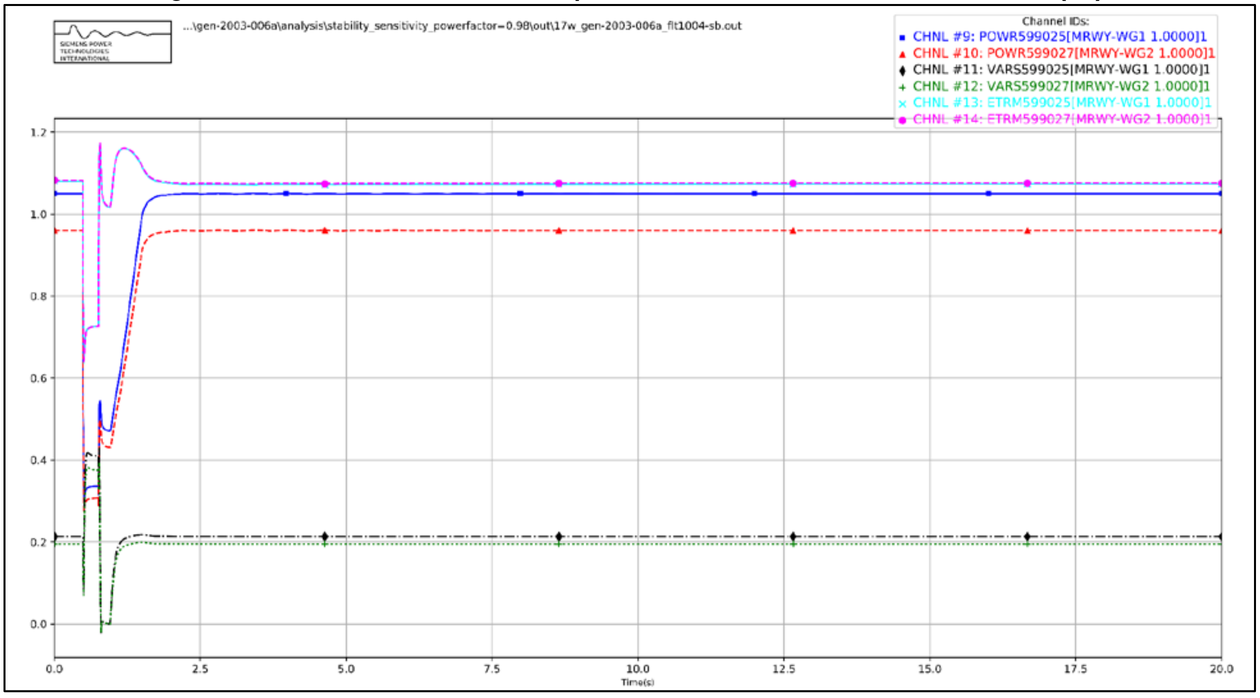


Figure 5-5: MRIS GEN-2003-006A Response to FLT1004-SB with GEN PF at 0.98 (S5)



Each of these pre-event set points may result in generating facility and transmission system voltages beyond the normal operating range (typically 0.95-1.05 pu) under certain system conditions. Vendor documentation indicated that the reactive power set point could be changed using 'ALTR' activity during simulation through adjusting VWVAR (L+1). This adjustment during simulation could not successfully be implemented in this study using the user-written model contained in VestasWT_7_5_0_PSSE33.lib and executed through PSS/E V33.7. A Vestas WTG PSS/E model with a dynamic reactive power control response, not available with the VWCOR4 user-written model, may provide a portion of the necessary dynamically controlled reactive power without requiring the PSS/E user to implement a specific pre-event reactive power set point. A newer version of the Vestas user-written model may be available that provides this enhanced functionality and should be provided to SPP for inclusion in future studies.

Four sensitivity cases were simulated with the existing GEN-2003-006A configuration with the STATCOM devices switched offline to understand the impact of the modified GEN-2003-006A configuration. Figure 5-6 shows that with a unity power factor and initializing the facility capacitor banks at 36 MVAR prior to the event, the response was unstable (S6). Figure 5-7 shows that with setting the generator power factor to 0.98 lagging (providing vars) and with the capacitor banks offline prior to the event the result was also an unstable simulation (S7).

Figure 5-6: Orig. GEN-2003-006A - FLT1004-SB with 36 MVAR Cap and STATCOM Offline (S6)

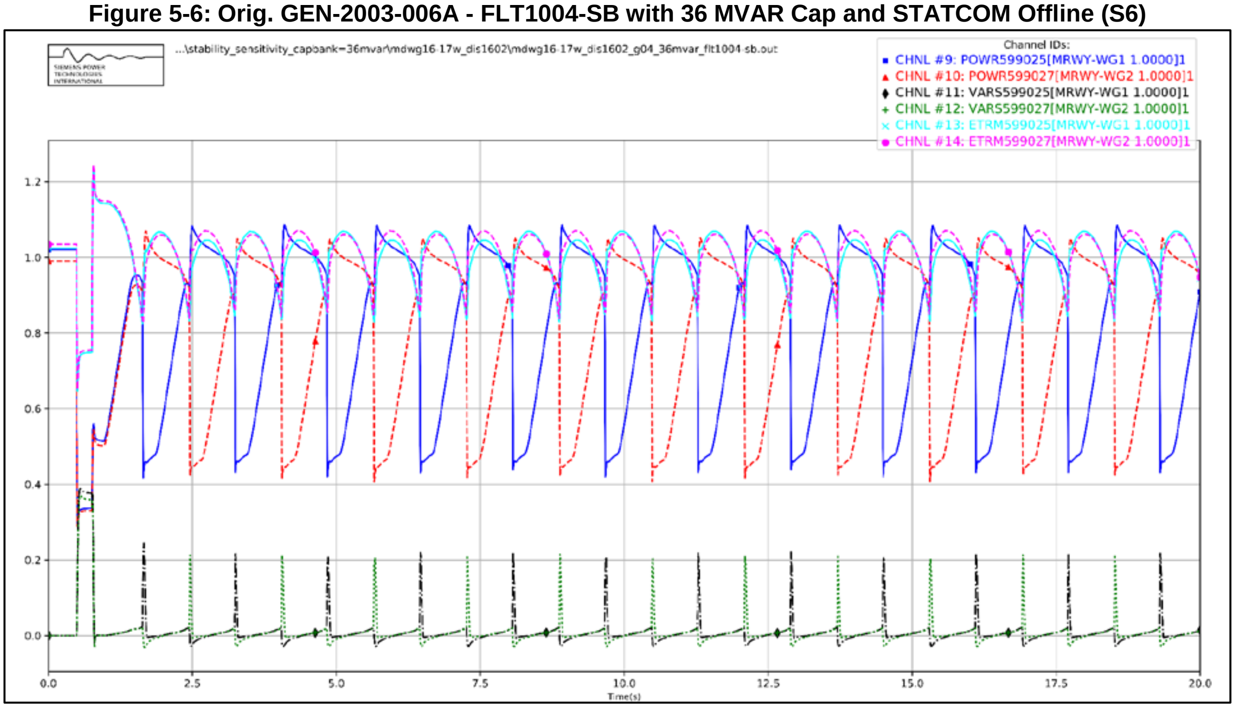
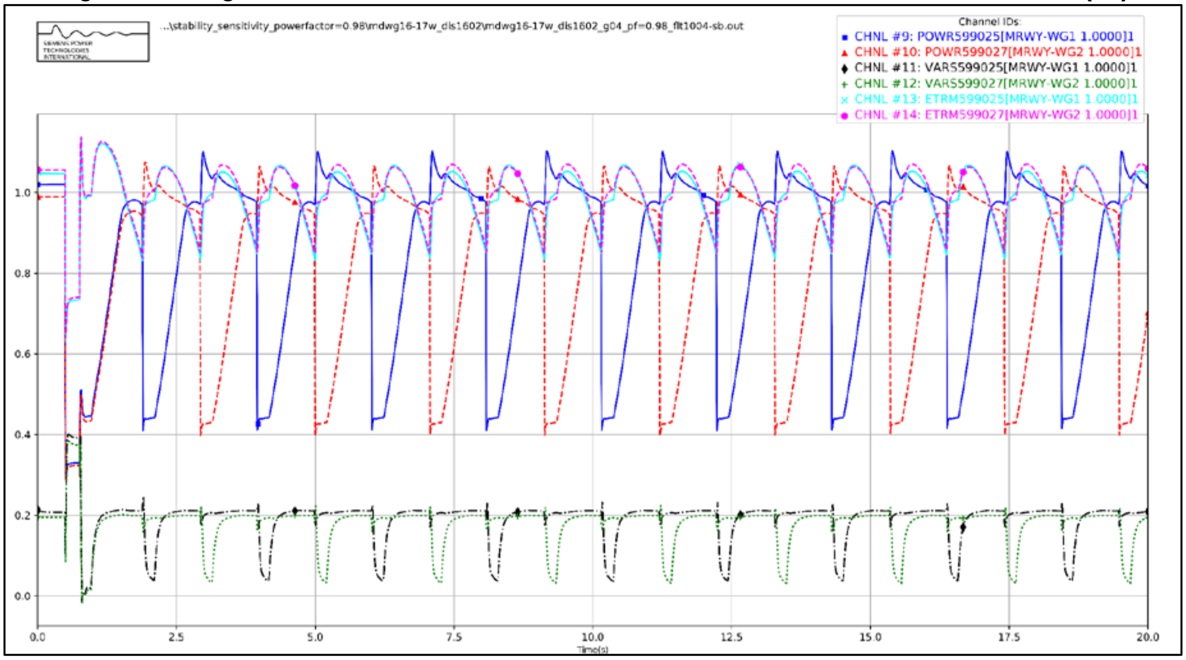


Figure 5-7: Orig. GEN-2003-006A - FLT1004-SB with GEN PF at 0.98 and STATCOM Offline (S7)



A simulation was analyzed with the existing GEN-2003-006A configuration with the STATCOM devices switched offline when the capacitor banks were set to 36 MVAR and the generator power factor was set to 0.98 lagging (providing vars) prior to the event as shown in Figure 5-8 (S8A). In this scenario, a portion of the GEN-2003-006A generating facility protection relays tripped on high voltage. A stable simulation was achieved with this combination when the main power transformer tap was set to 1.05 on the 230 kV side and the generator step-up transformer tap was set to 1.025 on the 34.5 kV side to mitigate high voltage tripping in Figure 5-9 (S8).

Figure 5-8: Orig. GEN-2003-006A - FLT1004-SB: 36 MVAR Cap, GEN PF at 0.98, and STATCOM Offline (S8A)

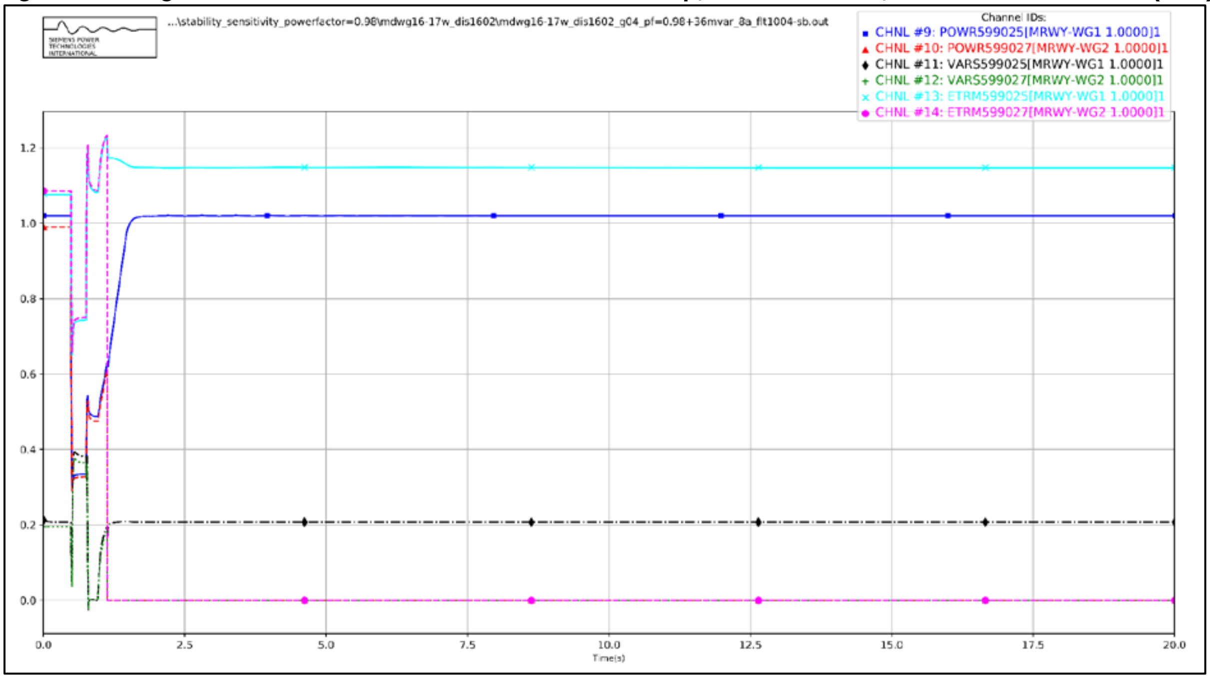
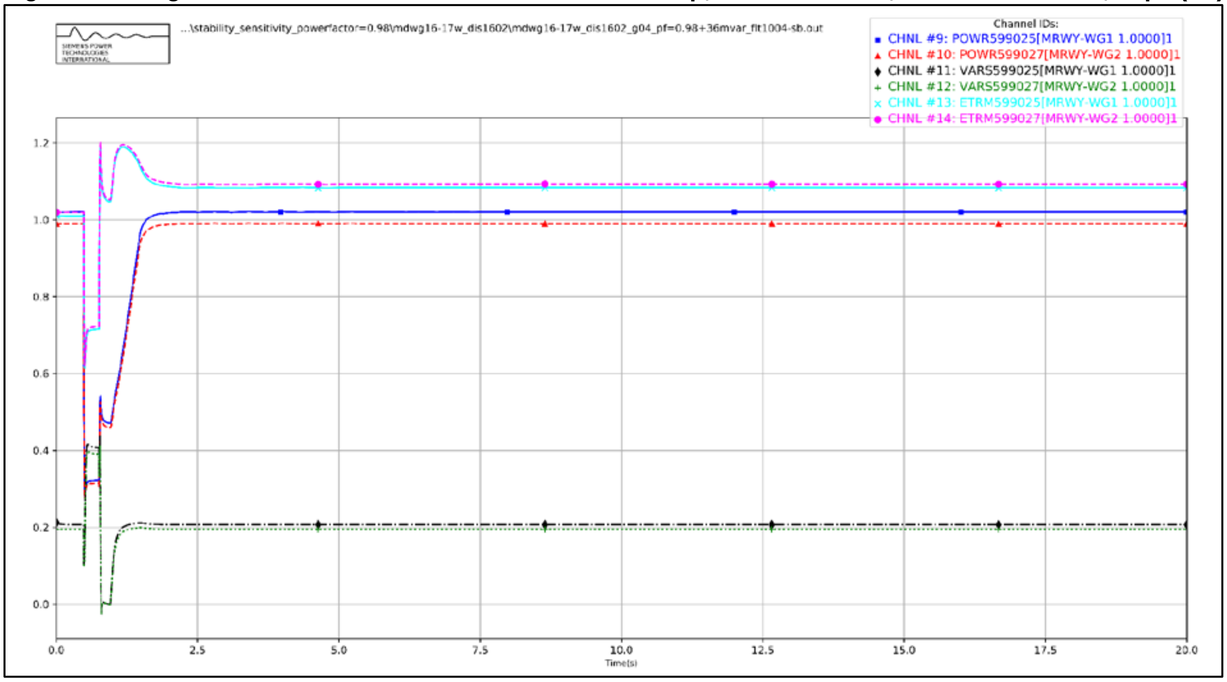


Figure 5-9: Orig. GEN-2003-006A - FLT1004-SB: 36 MVAR Cap, GEN PF at 0.98, STATCOM Offline, Taps (S8)



Three sensitivity cases were simulated with the existing GEN-2003-006A configuration with the STATCOM devices switched online.

Figure 5-10 shows that with the STATCOM devices switched online, initializing the facility capacitor banks at 36 MVAR, and the generator power factor being set to unity prior to the event, the response was unstable (S9). Figure 5-11 shows that with the STATCOM devices switched online, the generator power factor set to 0.99 lagging (providing vars), and the capacitor banks set to 36 MVAR (S10A) a portion of the GEN-2003-006A generating facility protection relays tripped on high voltage. A stable simulation was found with this combination when the transformer tap points were adjusted similarly to Scenario 8 as shown in Figure 5-12 (S10). Scenario 8 and 10 show that a stable response can be achieved if the capacitor banks are dispatched at 36 MVAR, the generator power factor is at least 0.99, and the transformer tap points are adjusted regardless of the STATCOM status.

Figure 5-10: Orig. GEN-2003-006A - FLT1004-SB: 36 MVAR Cap, and STATCOM Online (S9)

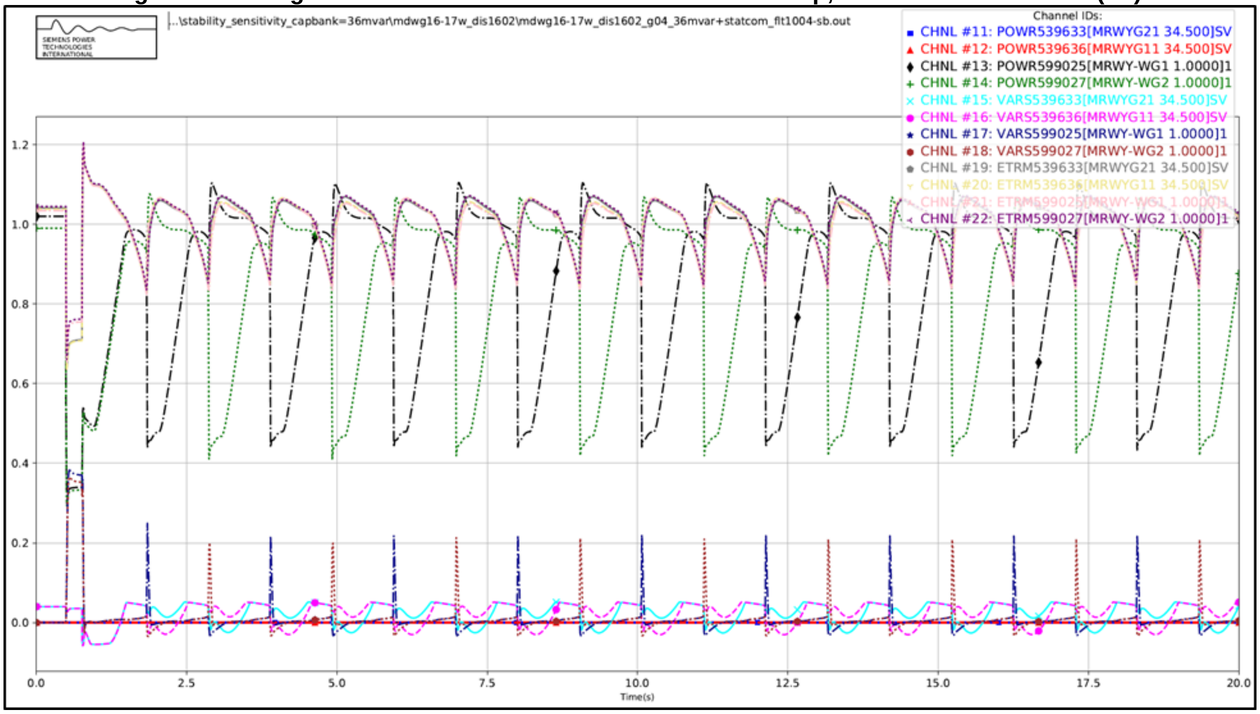


Figure 5-11: Orig. GEN-2003-006A - FLT1004-SB: 36 MVAR Cap, GEN PF at 0.99, and STATCOM Online (S10A)

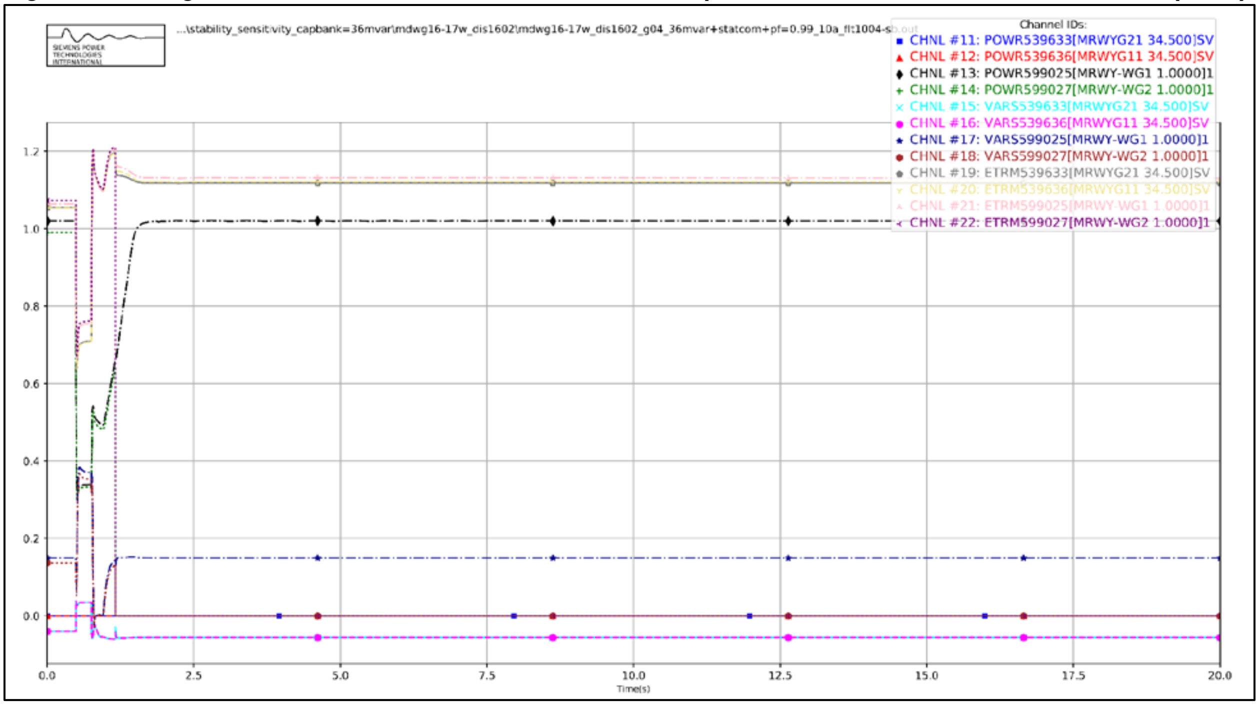
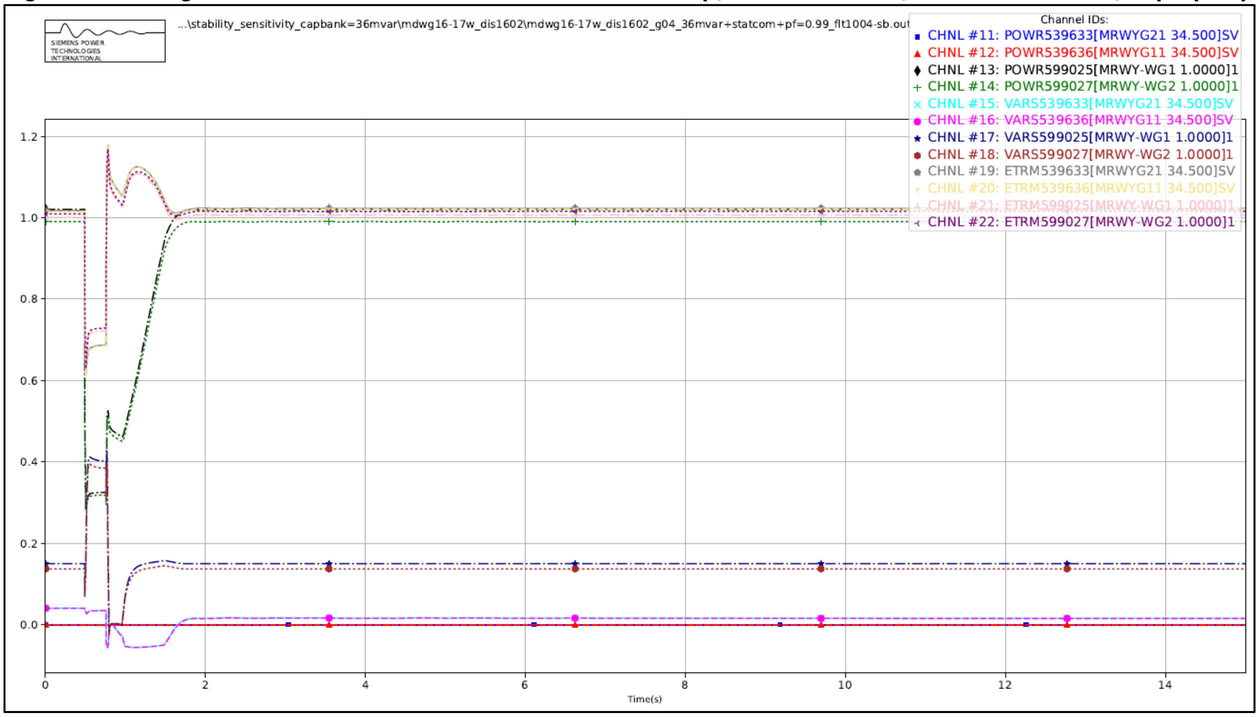


Figure 5-12: Orig. GEN-2003-006A - FLT1004-SB: 36 MVAR Cap, GEN PF at 0.99, STATCOM Online, Taps (S10)



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.

6.0 Conclusions

The Interconnection Customer for GEN-2003-006A requested a Modification Request Impact Study to assess the impact of the facility change to remove the STATCOM devices on the 34.5 kV collection buses. The configuration of 67 x Vestas V-90 3.0MW for a total capacity of 201 MW did not change. In addition, the modification request included updates to the collection system, main substation transformer, and GSU transformers.

A power factor analysis was not performed as there was no change in the point of interconnection for GEN-2003-006A.

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-2003-006A project may require a 9.6 MVAr (updated configuration) shunt reactor on the 34.5 kV buses of the project substation which is increased from 4.4 MVAr (existing configuration) 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 the short circuit analysis with the updated topology showed that the maximum GEN-2003-006A contribution to three-phase fault currents in the immediate systems at or near GEN-2003-006A was approximately 1.15 kA for the 2018SP and 2026SP cases. All three-phase fault current levels, within 5 buses of the POI, with the GEN-2003-006A generator online were below 26 kA for the 2018SP models and 2026SP models.

The results of the dynamic stability analysis showed that with the STATCOM devices disabled a combination of the loss of the Elm Creek to North Manhattan 230 kV line and a loss of the Elm Creek 345/230/13.8 kV transformer would cause GEN-2003-006A to become unstable in the 17WP case. This fault event resulted in the Elm Creek wind generating facility radially connecting through the Elm Creek to Concordia 230kV circuit and Concordia 230/115 kV transformer. This fault event was not analyzed in the previous SPP studies for GEN-2003-006A due to system configuration differences.

Sensitivity cases were run for this fault event (FLT1004-SB). The results indicate that with the existing (2016 MDWG) generating facility topology, a stable system response may be achieved without the STATCOM devices by adjusting the facility reactive power set point and transformer taps. With the updated generating facility topology, a stable system response may be achieved without the STATCOM devices by adjusting the facility reactive power set point without adjusting transformer taps. The retirement of the STATCOM devices does not cause a new instability.

With the modification configuration changes, a post-event stable simulation at full output was achieved with a unity power factor by initializing the facility capacitor banks at 36 MVAR prior to the event (S3). Alternately, setting the generator power factor to 0.99 or 0.98 lagging (providing vars) and with the capacitor banks offline prior to the event also resulted in a stable simulation (S4 & S5).

A Vestas WTG PSS/E model with a dynamic reactive power control response, not available with the VWCOR4 user-written model, may provide a portion of the necessary dynamically controlled reactive power without requiring the PSS/E user to implement a specific pre-event reactive power set point. A newer version of the Vestas user-written model may be available that provides this enhanced functionality and should be provided to SPP for future studies.

There were no other machine rotor angle damping or transient voltage recovery violations observed in the simulated fault events for the generator 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.