Report on

GEN-2016-037
Modification Request Impact Study

Revision R1 **May 11, 2022**

Submitted to
Southwest Power Pool

SPP Southwest Power Pool

anedenconsulting.com

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDICES

Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
05/11/2022	Aneden Consulting	Initial Report Issued

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2016-037, an active Generation Interconnection Requests (GIR) with a point of interconnection (POI) at the G16-037-TAP 345 kV bus on the Chisholm to Gracemont 345 kV line.

The GEN-2016-037 project interconnects in the American Electric Power West (AEPW) 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-2016-037 to change the turbine configuration to 107 x GE 2.82 MW for a total capacity of 301.74 MW. This generating capacity for GEN-2016-037 (301.74 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 300 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line, and main substation transformers. The existing and modified configurations for GEN-2016-037 are shown in Table ES-2.

Table ES-1: GEN-2016-037 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2016-037	Tap on Chisholm (511553) to Gracemont (515800) 345kV Line (G16-037-TAP 560078)	150 x Vestas 2.0 MW	300

Table ES-2: GEN-2016-037 Modification Request

Facility	Existing Configuration		Modification Configuration	
Point of Interconnection	Tap on Chisholm (511553) to Gracemont (515800) 345kV Line (G16-037-TAP 560078)		Tap on Chisholm (511553) to Gracemont (515800) 345kV Line (G16-037-TAP 560078)	
Configuration/Capacity	150 x Vestas 2.0 MW = 300 MW		107 x GE 2.82 MW = 301.74 MW	
Generation Interconnection Line	Length = 5.1 miles R = 0.000510 pu X = 0.003250 pu B = 0.034430 pu Rating MVA = 0 MVA		Length = 1.94 miles R = 0.000098 pu X = 0.000943 pu B = 0.017033 pu Rating MVA [A/B] = 855/1130 MVA	
Main Substation Transformer[1]	**MPT1:** X = 8.998%, R = 0.205%, Winding MVA = 120 MVA, Rating MVA = 200 MVA	**MPT2:** X = 8.998%, R = 0.205%, Winding MVA = 120 MVA, Rating MVA = 200 MVA	**MPT1:** X = 9.658%, R = 0.184%, Winding MVA = 144 MVA, Rating MVA = 225 MVA	**MPT2:** X = 9.688%, R = 0.22%, Winding MVA = 100 MVA, Rating MVA = 166 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 150 X = 7.759%, R = 0.799%, Winding MVA = 315 MVA, Rating MVA = 315 MVA		Gen 1 Equivalent Qty: 71 X = 5.935%, R = 0.424%, Winding MVA = 216.55 MVA, Rating MVA[2] = 216.6 MVA	Gen 2 Equivalent Qty: 36: X = 5.935%, R = 0.424%, Winding MVA = 109.8 MVA, Rating MVA = 109.8 MVA
Equivalent Collector Line[3]	R = 0.003368 pu X = 0.005377 pu B = 0.263280 pu		R = 0.008608 pu X = 0.014112 pu B = 0.200088 pu	R = 0.008634 pu X = 0.013286 pu B = 0.056960 pu
Generator Dynamic Model[4] & Power Factor	150 x Vestas 2.0 MW (REGCAU1)[4] ±0.991		71 x GE 2.82 MW (GEWTG0705)[4] ±0.925	36 x GE 2.82 MW (GEWTG0705)[4] ±0.925

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

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.68% compared to the DISIS-2017-001 power flow models. However, SPP determined that the turbine change from Vestas to GE required short circuit and dynamic stability analyses.

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

Aneden performed the analyses using the modification request data based on the DISIS 2017-001 stability study models:

1. 2019 Winter Peak (2019WP),
2. 2021 Light Load (2021LL),
3. 2021 Summer Peak (2021SP),
4. 2028 Summer Peak (2028SP)

Aneden reviewed nearby GIRs and updated as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the GEN-2011-010, GEN-2014-005, and GEN-2016-091 project configurations in the base models.

All analyses were performed using the PTI PSS/E version 33 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak models showed that the GEN-2016-037 project needed 27.45 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 29.8 MVAr found for the existing GEN-2016-037 configuration calculated using the DISIS-2017-001 models. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The results from the short circuit analysis with the updated configuration showed that the maximum GEN-2016-037 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2016-037 POI was no greater than 1.24 kA for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-037 generators online were below 46 kA for the 2021SP and 2028SP models.

The dynamic stability analysis was performed using PTI PSS/E version 33.10 software for the four modified study models, 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak. Up to 29 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

There were no damping or voltage recovery violations attributed to the GEN-2016-037 project observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

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

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

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

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

1.0 Scope of Study

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2016-037. A Modification Request Impact Study is a generation interconnection study performed to evaluate the impacts of modifying the DISIS study assumptions. The determination of the required scope of the study is dependent upon the specific modification requested and how it may impact the results of the DISIS study. Impacting the DISIS results could potentially affect the cost or timing of any Interconnection Request with a later Queue priority date, deeming the requested modification a Material Modification. The criteria sections below include reasoning as to why an analysis was either included or excluded from the scope of study.

All analyses were performed using the PTI PSS/E version 33 software. The results of each analysis are presented in the following sections.

1.1 Power Flow Analysis

To determine whether power flow analysis is required, SPP evaluates the difference in the real power output at the POI between the DISIS-2017-001 power flow configuration and the requested modification. Power flow analysis is performed if the difference in the real power may result in a significant impact on the results of the DISIS power flow analysis.

1.2 Dynamic Stability Analysis, Short Circuit Analysis

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

1.3 Charging Current Compensation Analysis

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

1.4 Study Limitations

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

2.0 Project and Modification Request

The GEN-2016-037 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the G16-037-TAP 345 kV bus on the Chisholm to Gracemont 345 kV line. At the time of the posting of this report, GEN-2016-037 is an active Interconnection Request with queue status of "IA FULLY EXECUTED/ON SCHEDULE." GEN-2016-037 is a wind farm and has a maximum summer and winter queue capacity of 300 MW with Energy Resource Interconnection Service (ERIS).

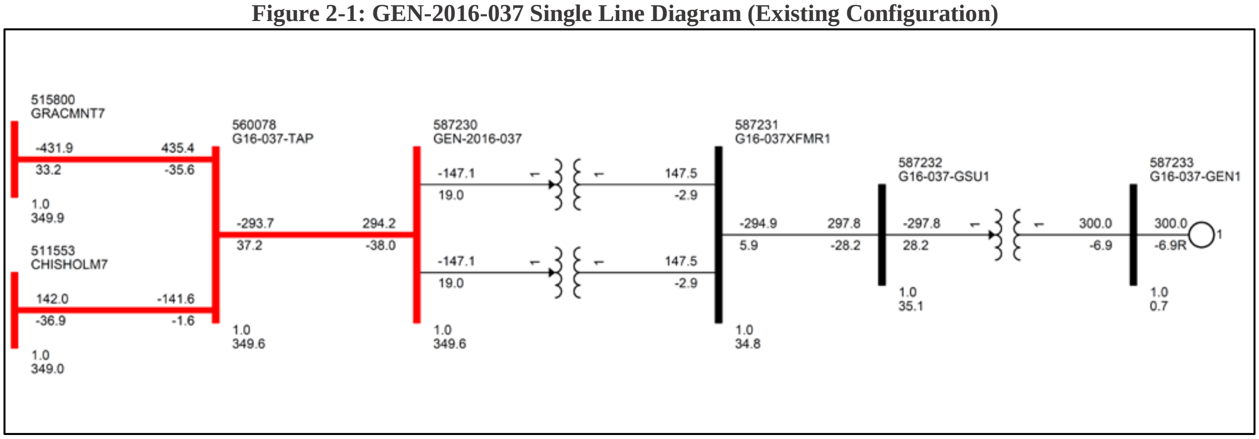
The GEN-2016-037 project is currently in the DISIS-2017-001 cluster. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2016-037 configuration.

The GEN-2016-037 project interconnects in the American Electric Power West (AEPW) control area with a capacity of 300 MW as shown in Table 2-1 below.

Table 2-1: GEN-2016-037 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2016-037	Tap on Chisholm (511553) to Gracemont (515800) 345kV Line (G16-037-TAP 560078)	150 x Vestas 2.0 MW	300

Figure 2-1: GEN-2016-037 Single Line Diagram (Existing Configuration)



This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2016-037 to a turbine configuration of 107 x GE 2.82 MW for a total capacity of 301.74 MW. This combined generating capacity for GEN-2016-037 (301.74 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, 300 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line, and main substation transformers. Figure 2-2 shows the power flow model single line diagram for the GEN-2016-037 modification. The existing and modified configurations for GEN-2016-037 are shown in Table 2-2.

Figure 2-2: GEN-2016-037 Single Line Diagram (Modification Configuration)

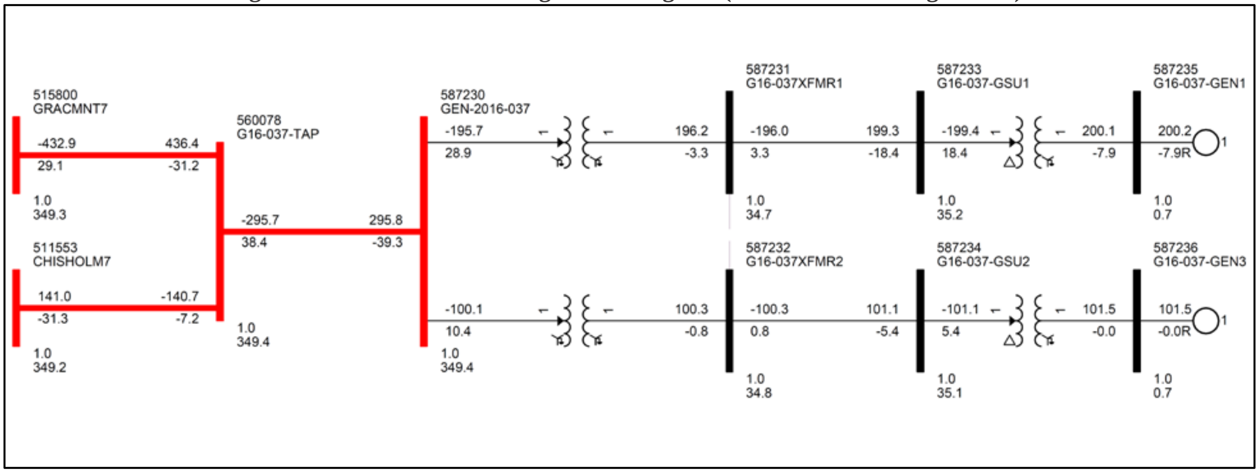


Table 2-2: GEN-2016-037 Modification Request

Facility	Existing Configuration		Modification Configuration	
Point of Interconnection	Tap on Chisholm (511553) to Gracemont (515800) 345kV Line (G16-037-TAP 560078)		Tap on Chisholm (511553) to Gracemont (515800) 345kV Line (G16-037-TAP 560078)	
Configuration/Capacity	150 x Vestas 2.0 MW = 300 MW		107 x GE 2.82 MW = 301.74 MW	
Generation Interconnection Line	Length = 5.1 miles R = 0.000510 pu X = 0.003250 pu B = 0.034430 pu Rating MVA = 0 MVA		Length = 1.94 miles R = 0.000098 pu X = 0.000943 pu B = 0.017033 pu Rating MVA [A/B] = 855/1130 MVA	
Main Substation Transformer[1]	**MPT1:** X = 8.998%, R = 0.205%, Winding MVA = 120 MVA, Rating MVA = 200 MVA	**MPT2:** X = 8.998%, R = 0.205%, Winding MVA = 120 MVA, Rating MVA = 200 MVA	**MPT1:** X = 9.658%, R = 0.184%, Winding MVA = 144 MVA, Rating MVA = 225 MVA	**MPT2:** X = 9.688%, R = 0.22%, Winding MVA = 100 MVA, Rating MVA = 166 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 150 X = 7.759%, R = 0.799%, Winding MVA = 315 MVA, Rating MVA = 315 MVA		Gen 1 Equivalent Qty: 71 X = 5.935%, R = 0.424%, Winding MVA = 216.55 MVA, Rating MVA[2] = 216.6 MVA	Gen 2 Equivalent Qty: 36: X = 5.935%, R = 0.424%, Winding MVA = 109.8 MVA, Rating MVA = 109.8 MVA
Equivalent Collector Line[3]	R = 0.003368 pu X = 0.005377 pu B = 0.263280 pu		R = 0.008608 pu X = 0.014112 pu B = 0.200088 pu	R = 0.008634 pu X = 0.013286 pu B = 0.056960 pu
Generator Dynamic Model[4] & Power Factor	150 x Vestas 2.0 MW (REGCAU1)[4] ±0.991		71 x GE 2.82 MW (GEWTG0705)[4] ±0.925	36 x GE 2.82 MW (GEWTG0705)[4] ±0.925

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

3.0 Existing vs Modification Comparison

To determine which analyses are required for the Study, the differences between the existing configuration and the requested modification were evaluated. Aneden performed this comparison and the resulting analyses using a set of modified study models developed based on the modification request data and the DISIS-2017-001 study models.

Aneden reviewed nearby GIRs and updated as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the GEN-2011-010 & GEN-2014-005 and GEN-2016-091 project configurations in the base models.

The methodology and results of the comparisons are described below. The analysis was completed using PSS/E version 33 software.

3.1 POI Injection Comparison

The real power injection at the POI was determined using PSS/E to compare the DISIS-2017-001 power flow configuration and the requested modification for GEN-2016-037. The percentage change in the POI injection was then evaluated. If the real power (MW) difference was determined to be significant (greater than 10%) power flow analysis would be performed to assess the impact of the modification request.

SPP determined that power flow analysis was not required due to the insignificant change, increase of 0.68%, in the real power output at the POI between the studied DISIS-2017-001 power flow configuration and requested modification shown in Table 3-1.

Table 3-1: GEN-2016-037 POI Injection Comparison

Interconnection Request	Existing POI Injection (MW)	Modification POI Injection (MW)	POI Injection Difference %
GEN-2016-037	293.7	295.7	0.68%

3.2 Turbine Parameters Comparison

SPP determined that short circuit and dynamic stability analyses were required because of the turbine change from Vestas to GE. This is because the short circuit contribution and stability responses of the existing configuration and the requested modification's configuration may differ. The generator dynamic model for the modification can be found in Appendix A.

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

3.3 Equivalent Impedance Comparison Calculation

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

4.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2016-037 to determine the capacitive charging effects during reduced generation conditions (unsuitable wind speeds, unsuitable solar irradiance, insufficient state of charge, idle conditions, curtailment, etc.) at the generation site and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

4.1 Methodology and Criteria

The GEN-2016-037 generators were switched out of service while other collection system elements remained in-service. A shunt reactor was tested at the project's collection substation 34.5 kV bus to offset the MVAr flow into the POI to approximately zero. The size of the shunt reactor is equivalent to the charging current value at unity voltage and the compensation provided is proportional to the voltage effects on the charging current (i.e., for voltages above unity, reactive compensation is greater than the size of the reactor).

4.2 Results

The results from the analysis showed that the GEN-2016-037 project needed approximately 27.45 MVAr of compensation at its collector substation, to reduce the POI MVAr to zero. This is a decrease from the 29.8 MVAr found for the existing GEN-2016-037 configuration calculated using the DISIS-2017-001 models. The final shunt reactor requirements for GEN-2016-037 are shown in Table 4-1. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the existing configuration.
Figure 4-2 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the updated configuration.

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

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

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)			
			19WP	21LL	21SP	28SP
GEN-2016-037	560078	G16-037-TAP 345 kV	27.45	27.45	27.45	27.45

Figure 4-1: GEN-2016-037 Single Line Diagram (Existing Shunt Reactor)

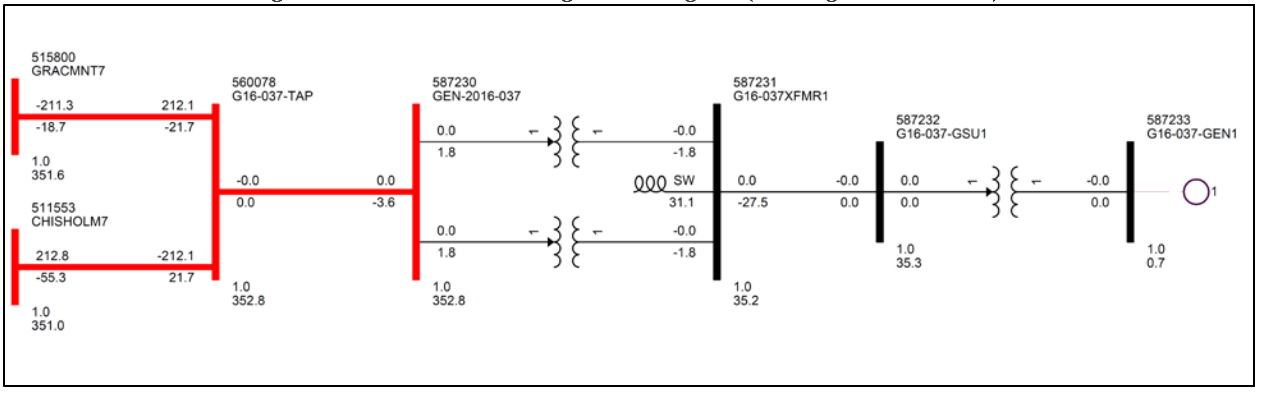
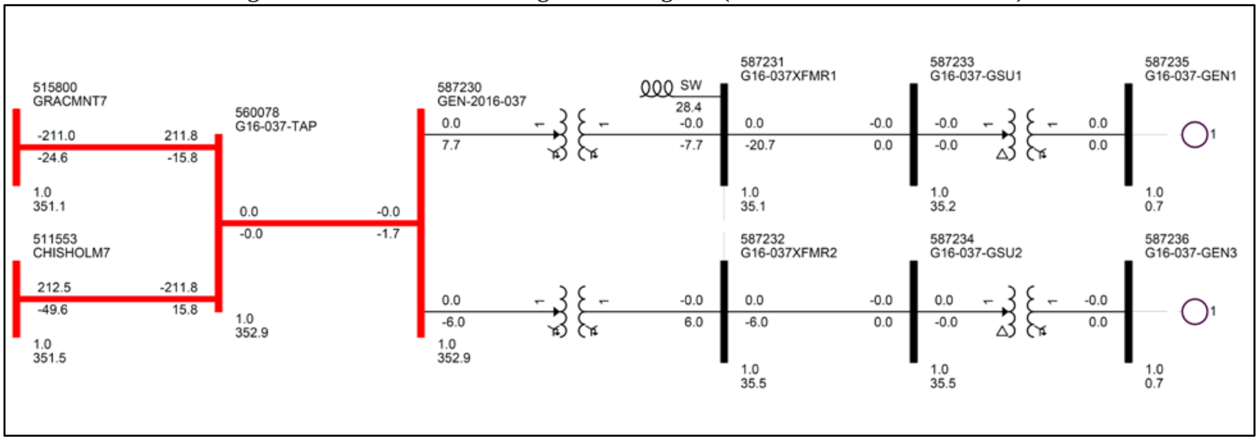


Figure 4-2: GEN-2016-037 Single Line Diagram (Modification Shunt Reactor)



5.0 Short Circuit Analysis

A short circuit study was performed using the 2021SP and 2028SP model for GEN-2016-037. The detailed results of the short circuit analysis are provided in Appendix B.

5.1 Methodology

The short circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 345 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels in the transmission system with and without GEN-2016-037 online.

5.2 Results

The results of the short circuit analysis for the 2021SP and 2028SP models are summarized in Table 5-1 through Table 5-3 respectively. The GEN-2016-037 POI bus (G16-037-TAP 345 kV - 560078) fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 7.61 kA with the GEN-2016-037 project online.

The maximum fault current calculated within 5 buses of the GEN-2016-037 POI was less than 46 kA for the 2021SP and 2028SP models respectively. The maximum GEN-2016-037 contribution to three-phase fault currents was about 19.5% and 1.24 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2021SP	6.35	7.58	1.23	19.4%
2028SP	6.36	7.61	1.24	19.5%

Table 5-2: 2021SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	16.5	0.01	0.1%
115	6.5	0.01	0.2%
138	45.3	0.20	0.9%
230	8.7	0.39	4.7%
345	34.8	1.23	19.4%
Max	**45.3**	**1.23**	**19.4%**

Table 5-3: 2028SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	20.1	0.02	0.2%
115	6.5	0.02	0.3%
138	45.2	0.21	1.2%
230	8.6	0.40	4.9%
345	34.8	1.24	19.5%
Max	**45.2**	**1.24**	**19.5%**

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine configuration change and other modifications to the GEN-2016-037 project. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix C. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix A. The simulation plots can be found in Appendix D.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested GEN-2016-037 configuration of 107 x GE 2.82 MW (GEWTG0705). This stability analysis was performed using PTI's PSS/E version 33.10 software.

The stability models were developed using the DISIS-2017-001 models. The modifications requested for the GEN-2016-037 project were used to create modified stability models for this impact study.

Aneden reviewed nearby GIRs and updated as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the GEN-2011-010, GEN-2014-005, and GEN-2016-091 project configurations in the base models.

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

1. The capacitor bank at the Dempsey 34.5 kV bus (511961) was switched online
2. The capacitor bank at the Bowers 69 kV bus (523747) was switched online in the 19WP prior outage cases
3. The Grapevine 230/115 kV transformer tap was set to 1.0 in the 19WP prior outage cases

The modified dynamics model data for the GEN-2016-037 project is provided in Appendix A. The modified power flow models and associated dynamics database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2016-037 and other equally and prior queued projects in the cluster group[1]. In addition, voltages of five (5) buses away from the POI of GEN-2016-037 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 520 (AEPW), 524 (OKGE), 525 (WFEC), 526 (SPS), 531 (MIDW), 534 (SUNC), 536 (WERE) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

6.2 Fault Definitions

Aneden simulated the faults previously simulated for GEN-2016-037 and developed additional fault events 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 stuck breaker faults. The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and the 2028 Summer Peak models.

[1] Based on the DISIS-2017-001 Cluster Groups

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT23-3PH	P1	3 phase fault on CHISHOLM7 345kV (511553)/230kV (511557)/13.2kV (511558) transformer CKT 1, near CHISHOLM7 345kV. a. Apply fault at the CHISHOLM7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT27-3PH	P1	3 phase fault on the MINCO 7 (514801) to CIMARON7 (514901) 345 kV line CKT 1, near MINCO 7. a. Apply fault at the MINCO 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT32-3PH	P1	3 phase fault on the GRACMNT7 (515800) to G16-091-TAP (587744) 345 kV line CKT 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT33-3PH	P1	3 phase fault on GRACEMN7 345kV (515800)/138kV (515802)/13.8kV (515801) transformer CKT 1, near GRACEMN7 345kV. a. Apply fault at the GRACEMN7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT34-3PH	P1	3 phase fault on the GRACMNT7 (515800) to MINCO 7 (514801) 345 kV line CKT 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT47-3PH	P1	3 phase fault on the GRACMNT7 (515800) to G16-037-TAP (560078) 345 kV line CKT 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT48-3PH	P1	3 phase fault on the G16-091-TAP (587744) to L.E.S.-7 (511468) 345 kV line CKT 1, near G16-091-TAP. a. Apply fault at the G16-091-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT65-3PH	P1	3 phase fault on the CIMARON7 (514901) to MINCO 7 (514801) 345 kV line CKT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9001-3PH	P1	3 phase fault on the G16-037-TAP (560078) to CHISHOLM7 (511553) 345 kV line CKT 1, near G16-037-TAP. a. Apply fault at the G16-037-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on the G16-037-TAP (560078) to GRACMNT7 (515800) 345 kV line CKT 1, near G16-037-TAP. a. Apply fault at the G16-037-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1	3 phase fault on the GRACMNT7 (515800) to GEN-2015-093 (563269) 345 kV line CKT 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator G15-093-GEN1 (563272) Trip generator G15-093-GEN2 (563273) c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9004-3PH	P1	3 phase fault on the G16-091-TAP (587744) to GEN-2016-095 (587770) 345 kV line CKT 1, near G16-091-TAP. a. Apply fault at the G16-091-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator G16-095-GEN1 (587773) c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on the G16-091-TAP (587744) to GEN-2016-091 (587740) 345 kV line CKT 1, near G16-091-TAP. a. Apply fault at the G16-091-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator G16-095-GEN1 (587743) c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9006-3PH	P1	3 phase fault on the MINCO 7 (514801) to MCNOWND7 (515444) 345 kV line CKT 1, near MINCO 7. a. Apply fault at the MINCO 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator MNCOWNG1 (515907) c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9007-3PH	P1	3 phase fault on the MINCO 7 (514801) to MNCWND37 (515549) 345 kV line CKT 1, near MINCO 7. a. Apply fault at the MINCO 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator MNCWNDG1 (515921) Trip generator G15-057-GEN2 (584954) Trip generator G15-057-GEN3 (584955) Trip generator G15-057-GEN1 (584953) Trip generator G14-056-GEN2 (584064) Trip generator G14-056-GEN3 (584067) Trip generator MNCO4G11 (515943) c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 phase fault on the CHISHOLM6 (511557) to SWEETWT6 (511541) 230 kV line CKT 1, near CHISHOLM6. a. Apply fault at the CHISHOLM6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	P1	3 phase fault on the CHISHOLM6 (511557) to ELKCITY6 (511490) 230 kV line CKT 1, near CHISHOLM6. a. Apply fault at the CHISHOLM6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT32-PO1	P6	PRIOR OUTAGE of the G16-037-TAP (560078) to CHISHOLM7 (511553) 345 kV line CKT 1; 3 phase fault on the GRACMNT7 (515800) to G16-091-TAP (587744) 345 kV line CKT 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT33-PO1	P6	PRIOR OUTAGE of the G16-037-TAP (560078) to CHISHOLM7 (511553) 345 kV line CKT 1; 3 phase fault on GRACEMN7 345kV (515800)/138kV (515802)/13.8kV (515801) transformer CKT 1, near GRACEMN7 345kV. a. Apply fault at the GRACEMN7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT34-PO1	P6	PRIOR OUTAGE of the G16-037-TAP (560078) to CHISHOLM7 (511553) 345 kV line CKT 1; 3 phase fault on the GRACMNT7 (515800) to MINCO 7 (514801) 345 kV line CKT 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line.

		c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9003-PO1	P6	PRIOR OUTAGE of the G16-037-TAP (560078) to CHISHOLM7 (511553) 345 kV line CKT 1; 3 phase fault on the GRACMNT7 (515800) to GEN-2015-093 (563269) 345 kV line CKT 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator G15-093-GEN1 (563272) Trip generator G15-093-GEN2 (563273) c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9008-PO2	P6	PRIOR OUTAGE of the G16-037-TAP (560078) to GRACMNT7 (515800) 345 kV line CKT 1; 3 phase fault on the CHISHOLM6 (511557) to SWEETWT6 (511541) 230 kV line CKT 1, near CHISHOLM6. a. Apply fault at the CHISHOLM6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9009-PO2	P6	PRIOR OUTAGE of the G16-037-TAP (560078) to GRACMNT7 (515800) 345 kV line CKT 1; 3 phase fault on the CHISHOLM6 (511557) to ELKCITY6 (511490) 230 kV line CKT 1, near CHISHOLM6. a. Apply fault at the CHISHOLM6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT1001-SB	P4	Stuck Breaker on GRACMNT7 (515800) 345kV bus. a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the GRACMNT 345kV (515800) / 138kV (515802) / 13.8kV (515801) transformer CKT 1. d. Trip the GRACMNT7 (515800) to G16-091-TAP (587744) 345 kV line CKT 1.
FLT1002-SB	P4	Stuck Breaker on GRACMNT7 (515800) 345kV bus. a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the GRACMNT7 (515800) to G16-091-TAP (587744) 345 kV line CKT 1. d. Trip the GRACMNT7 (515800) to GEN-2015-093 (563269) 345 kV line CKT 1. Trip generator G15-093-GEN1 (563272) Trip generator G15-093-GEN2 (563273)
FLT1003-SB	P4	Stuck Breaker on GRACMNT7 (515800) 345kV bus. a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the GRACMNT7 (515800) to G16-037-TAP 7 (560078) 345 kV line CKT 1. d. Trip the GRACMNT7 (515800) to MINCO 7 (514801) 345 kV line CKT 1.
FLT1004-SB	P4	Stuck Breaker on GRACMNT7 (515800) 345kV bus. a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the GRACMNT7 (515800) to G16-037-TAP 7 (560078) 345 kV line CKT 1. d. Trip the GRACMNT 345kV (515800) / 138kV (515802) / 13.8kV (515801) transformer CKT 1.
FLT1005-SB	P4	Stuck Breaker on GRACMNT7 (515800) 345kV bus. a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the GRACMNT7 (515800) to GEN-2015-093 (563269) 345 kV line CKT 1. d. Trip the GRACMNT7 (515800) to MINCO 7 (514801) 345 kV line CKT 1. Trip generator G15-093-GEN1 (563272) Trip generator G15-093-GEN2 (563273)
FLT1006-SB	P4	Stuck Breaker on CHISHOLM7 345kV (511553) at 345kV bus a. Apply single-phase fault at CHISHOLM7 345kV (511553) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the Bus CHISHOLM7 345kV (511553).

6.3 Results

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

Table 6-2: GEN-2016-037 Dynamic Stability Results

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT23-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT27-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT32-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT33-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT34-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT47-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT48-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT65-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable*	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT32-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT33-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT34-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

***RELAY SLNOS1 tripped 523777 [WHEELER 6230.00] TO 511541 [SWEETWT6 230.00] CKT 1 during the fault**

During fault FLT9008-3PH (loss of CHISHOLM to SWEETWT 230 kV line), the SLNOS1 relay tripped the WHEELER to SWEETWT 230 kV Circuit #1 line during the fault in the 19WP cases. This was observed in both the pre and post modification cases, so it was not attributed to this modification request. The SLNOS1 relay was disabled in the models while running the dynamic stability analysis.

There were no damping or voltage recovery violations attributed to the GEN-2016-037 project observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

7.0 Modified Capacity Exceeds GIA Capacity

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

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

7.1 Results

The modified generating capacity of GEN-2016-037 (301.74 MW) exceeds the GIA Interconnection Service amount, 300 MW, as listed in Appendix A of the GIA.

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

8.0 Material Modification Determination

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

8.1 Results

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

This determination implies that any network upgrades already required by GEN-2016-037 would not be negatively impacted and that no new upgrades are required due to the requested modification, thus not resulting in a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.

9.0 Conclusions

The Interconnection Customer for GEN-2016-037 requested a Modification Request Impact Study to assess the impact of the turbine and facility change to 107 x GE 2.82 MW for a total combined capacity of 301.74 MW. The combined generating capacity of GEN-2016-037 (301.74 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 300 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

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

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.68% compared to the DISIS-2017-001 power flow models. However, SPP determined that the turbine change from Vestas to GE required short circuit and dynamic stability analyses.

Aneden reviewed nearby GIRs and updated as applicable based on SPP’s confirmation of the latest project configurations. As a result, Aneden updated the GEN-2011-010, GEN-2014-005, and GEN-2016-091 project configurations in the base models.

All analyses were performed using the PTI PSS/E version 33 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak models showed that the GEN-2016-037 project needed 27.45 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 29.8 MVAr found for the existing GEN-2016-037 configuration calculated using the DISIS-2017-001 models. This is necessary to offset the capacitive effect on the transmission network caused by the project’s transmission line and collector system during low-wind or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The results from the short circuit analysis with the updated configuration showed that the maximum GEN-2016-037 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2016-037 POI was not greater than 1.24 kA for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-037 generators online were below 46 kA for the 2021SP and 2028SP models.

The dynamic stability analysis was performed using PTI PSS/E version 33.10 software for the four modified study models, 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak. Up to 29 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

There were no damping or voltage recovery violations attributed to the GEN-2016-037 project observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

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

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

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

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