Submitted to
Southwest Power Pool

SPP Southwest Power Pool

Report On

GEN-2016-118
Modification Request Impact Study

Revision R1

Date of Submittal
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anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
02/08/2021	Aneden Consulting	Initial Report Issued.

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2016-118, an active generation interconnection request with a point of interconnection (POI) at the Dover Switchyard 138 kV bus.

The GEN-2016-118 project is proposed to interconnect in the Western Farmers Electric Cooperative (WFEC) control area with a capacity of 288 MW as shown in Table ES-1 below. This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2016-118 from the previously studied 144 x Vestas 2.0MW to a turbine configuration of 91 x GE 2.82 MW + 12 x GE 2.5 MW wind turbines for total capacity of 286.62 MW. In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformer, and the generation interconnection line. The modification request changes are shown in Table ES-2.

Table ES-1: GEN-2016-118 Existing Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2016-118	288	144 x Vestas 2.0MW = 288 MW	Dover Switchyard 138 kV (520882)

Table ES-2: GEN-2016-118 Modification Request

Facility	Existing	Modification			
Point of Interconnection	Dover Switchyard 138 kV (520882)	Dover Switchyard 138 kV (520882)			
Configuration/Capacity	144 x Vestas 2.0MW = 288 MW	91 x GE 2.82 MW + 12 x GE 2.5 MW = 286.62 MW			
Generation Interconnection Line	Length = 10 miles R = 0.001690 pu X = 0.030310 pu B = 0.014370 pu	Length = 23.37 miles R = 0.004762 pu X = 0.061293 pu B = 0.037862 pu			
Main Substation Transformer	X = 12.25%, R = 0.28%, Winding 180 MVA, Rate 300 MVA	X = 9%, R = 0.25%, Winding 141 MVA, Rating 235 MVA		X = 9%, R = 0.25%, Winding 141 MVA, Rating 235 MVA	
GSU Transformer	Gen 1 Equivalent Qty: 144: X = 7.76%, R = 0.8%, Rating 302.4 MVA	Gen 1 Equivalent Qty: 45: X = 6.97%, R = 0.66%, Rating 141.3 MVA	Gen 2 Equivalent Qty: 6: X = 6.48%, R = 0.606%, Rating 16.8 MVA	Gen 3 Equivalent Qty: 46: X = 6.97%, R = 0.66%, Rating 144.4 MVA	Gen 4 Equivalent Qty: 6: X = 6.48%, R = 0.606%, Rating 16.8 MVA
Equivalent Collector Line	R = 0.002600 pu X = 0.004200 pu B = 0.149210 pu	R = 0.008915 pu X = 0.011062 pu B = 0.073531 pu		R = 0.009151 pu X = 0.011377 pu B = 0.075784 pu	

SPP determined that power flow should not be performed based on the POI MW injection decrease of 1.53%. However, SPP determined that the turbine change from Vestas to GE turbines required short circuit and dynamic stability analyses.

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

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

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

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

The results of the charging current compensation analysis performed using the 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak models showed that the GEN-2016-118 project needed 18.84 MVAr of reactor shunts on the 34.5 kV bus of the project substation, an increase from the 16.36 MVAr found in the pre-modification case. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the customer and Transmission Owner. SPP does not require additional reactive requirements based on the results of this analysis.

The results from the short circuit analysis with the updated topology showed that the maximum GEN-2016-118 contribution to three-phase fault currents in the immediate systems at or near GEN-2016-118 was not greater than 2.17 kA for the 2018SP and 2026SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-118 generators online were below 42 kA for the 2018SP and 2026SP models.

The dynamic stability analysis was performed using the three DISIS-2016-002 models 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak. Up to 54 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

The results of the dynamic stability analysis showed that there were no damping or voltage recovery violations observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

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.

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-2016-118. A Modification Request Impact Study is a generation interconnection study performed to evaluate the impacts of modifying the DISIS study assumptions. The determination of the required scope of the study is dependent upon the specific modification requested and how it may impact the results of the DISIS study. Impacting the DISIS results could potentially affect the cost or timing of any Interconnection Request with a later Queue priority date, deeming the requested modification a Material Modification. The criteria sections below include reasoning as to why an analysis was either included or excluded from the scope of study.

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

1.1 Power Flow

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

1.2 Stability Analysis, Short Circuit Analysis

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

1.3 Charging Current Compensation Analysis

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

1.4 Study Limitations

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

2.0 Project and Modification Request

The GEN-2016-118 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the Dover Switchyard 138 kV bus. At the time of the posting of this report, GEN-2016-118 is an active IR with a queue status of “IA FULLY EXECUTED/ON SCHEDULE.” GEN-2016-118 is a wind farm, has a maximum summer and winter queue capacity of 288 MW, and has Energy Resource Interconnection Service (ERIS).

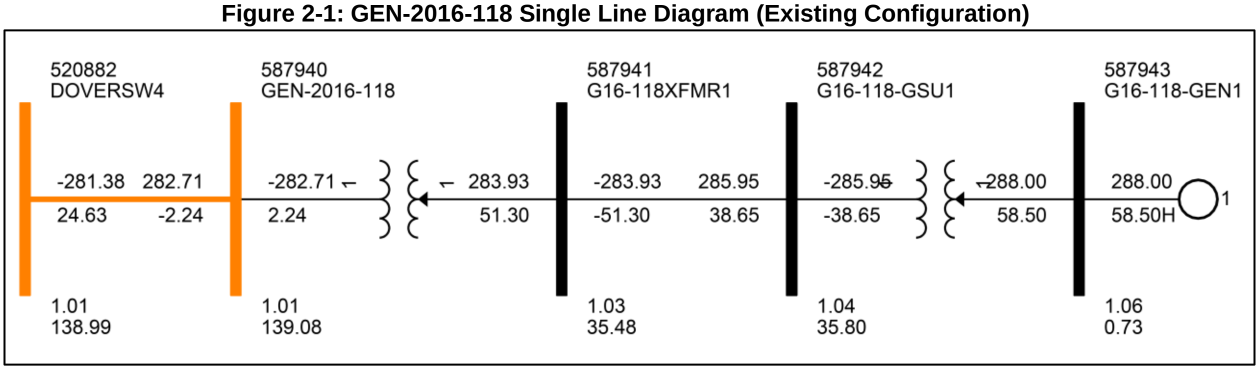
GEN-2016-118 was originally studied as part of Group 1 in the DISIS-2016-002-1 study. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2016-118 configuration.

The GEN-2016-118 project is proposed to interconnect in the Western Farmers Electric Cooperative (WFEC) control area with a combined nameplate capacity of 288 MW as shown in Table 2-1 below.

Table 2-1: GEN-2016-118 Existing Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2016-118	288	144 x Vestas 2.0MW = 288 MW	Dover Switchyard 138 kV (520882)

Figure 2-1: GEN-2016-118 Single Line Diagram (Existing Configuration)



This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2016-118 from the previously studied 144 x Vestas 2.0MW to a turbine configuration of 91 x GE 2.82 MW + 12 x GE 2.5 MW wind turbines for total capacity of 286.62 MW. In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformer, and the generation interconnection line. The modification request changes are shown in Figure 2-2 and Table 2-2 below.

Figure 2-2: GEN-2016-118 Single Line Diagram (Modification Configuration)

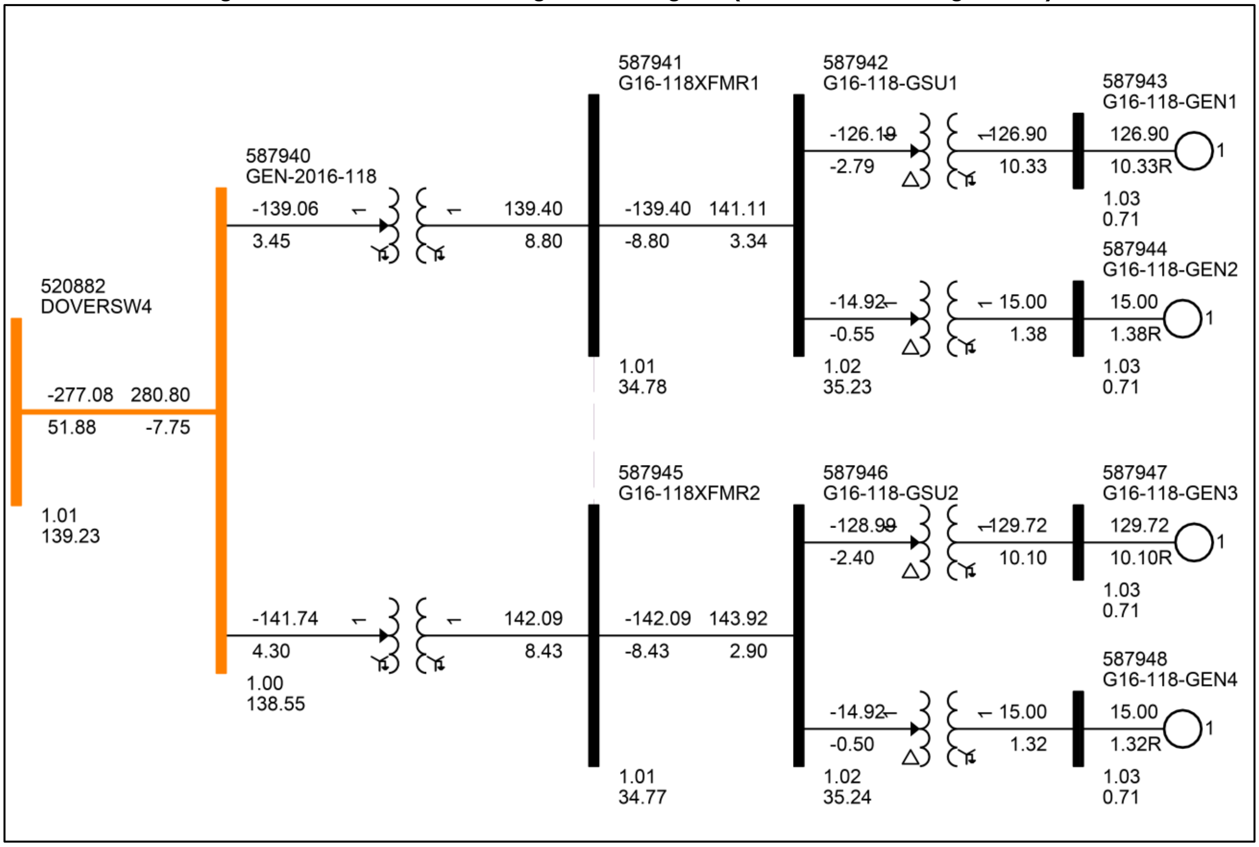


Table 2-2: GEN-2016-118 Modification Request

Facility	Existing	Modification			
Point of Interconnection	Dover Switchyard 138 kV (520882)	Dover Switchyard 138 kV (520882)			
Configuration/Capacity	144 x Vestas 2.0MW = 288 MW	91 x GE 2.82 MW + 12 x GE 2.5 MW = 286.62 MW			
Generation Interconnection Line	Length = 10 miles R = 0.001690 pu X = 0.030310 pu B = 0.014370 pu	Length = 23.37 miles R = 0.004762 pu X = 0.061293 pu B = 0.037862 pu			
Main Substation Transformer	X = 12.25%, R = 0.28%, Winding 180 MVA, Rate 300 MVA	X = 9%, R = 0.25%, Winding 141 MVA, Rating 235 MVA		X = 9%, R = 0.25%, Winding 141 MVA, Rating 235 MVA	
GSU Transformer	Gen 1 Equivalent Qty: 144: X = 7.76%, R = 0.8%, Rating 302.4 MVA	Gen 1 Equivalent Qty: 45: X = 6.97%, R = 0.66%, Rating 141.3 MVA	Gen 2 Equivalent Qty: 6: X = 6.48%, R = 0.606%, Rating 16.8 MVA	Gen 3 Equivalent Qty: 46: X = 6.97%, R = 0.66%, Rating 144.4 MVA	Gen 4 Equivalent Qty: 6: X = 6.48%, R = 0.606%, Rating 16.8 MVA
Equivalent Collector Line	R = 0.002600 pu X = 0.004200 pu B = 0.149210 pu	R = 0.008915 pu X = 0.011062 pu B = 0.073531 pu		R = 0.009151 pu X = 0.011377 pu B = 0.075784 pu	

3.0 Existing vs Modification Comparison

To determine which analysis is required, the differences between the existing configuration and the requested modification were evaluated.

Aneden performed this comparison and the resulting analyses using a set of modified study models developed based on the modification request data and the DISIS-2016-002 Group 1 study models.

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

3.1 POI Injection Comparison

The real power injection at the POI was determined using PSS/E for both the existing configuration and the requested modification with updates for GEN-2016-118. The percentage change in the POI injection before and after the modification request was then compared. If the MW difference was determined to be significant, power flow analysis would be performed to assess the impact of the modification request.

SPP determined that power flow analysis was not required due to the insignificant change (decrease of 1.53%) in the real power output at the POI between the existing configuration and requested modification shown in Table 3-1.

Table 3-1: GEN-2016-118 POI Injection Comparison

Interconnection Request	Existing POI Injection from Project (MW)	MRIS POI Injection from Project (MW)	POI Injection Difference from Project %
GEN-2016-118	281.4	277.1	-1.53%

3.2 Turbine Parameters Comparison

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

As short circuit and dynamic stability analyses were 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-2016-118 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-2016-118 generators and capacitors (if any) were switched out of service while other collector system elements remained in-service. A shunt reactor was tested at the phase's collection substation 34.5 kV bus to set the MVAr flow into the POI to approximately zero. The size of the shunt reactor is equivalent to the charging current value at unity voltage and the compensation provided is proportional to the voltage effects on the charging current (i.e. for voltages above unity, reactive compensation is greater than the size of the reactor).

4.2 Results

The results from the analysis showed that the GEN-2016-118 project needed an approximately 18.84 MVAr shunt reactor at the project substation, to reduce the POI MVAr to zero. This is an increase from the 16.36 MVAr found in the pre-modification case. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero in the pre-modification case. Figure 4-2 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the updated topology. The final shunt reactor requirements for GEN-2016-118 is shown in Table 4-1.

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

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

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)		
			17WP	18SP	26SP
GEN-2016-118	520882	Dover Switchyard 138 kV	18.84	18.84	18.84

Figure 4-1: GEN-2016-118 Single Line Diagram (Existing Shunt Reactor)

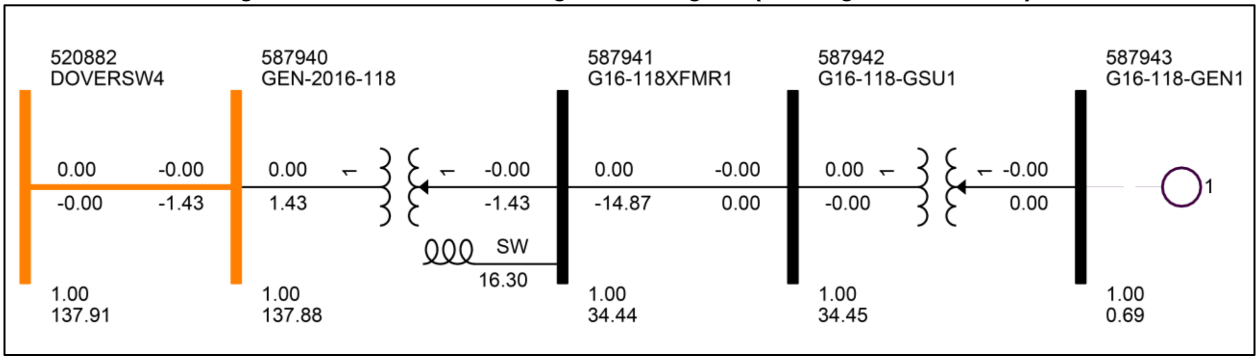
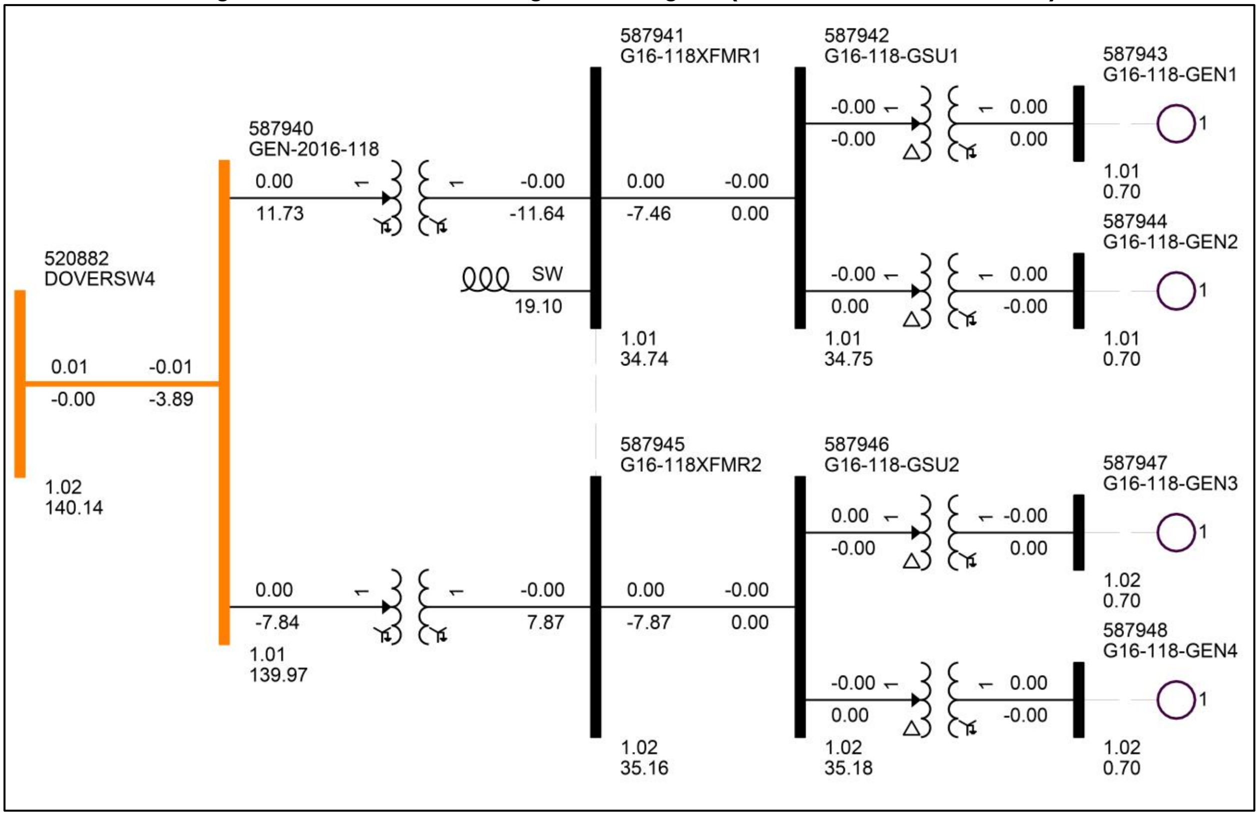


Figure 4-2: GEN-2016-118 Single Line Diagram (Modification Shunt Reactor)



5.0 Short Circuit Analysis

A short circuit study was performed using the 2018SP and 2026SP models for GEN-2016-118. 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 138 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels with and without GEN-2016-118 online.

5.2 Results

The results of the short circuit analysis for the 2018SP and 2026SP models are summarized in Table 5-1 through Table 5-3 respectively. The GEN-2016-118 POI bus fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 9.72 kA.

The maximum fault current calculated within 5 buses of the GEN-2016-118 POI was less than 42 kA for the 2018SP and 2026SP models respectively. The maximum GEN-2016-118 contribution to three-phase fault current was about 28.9% and 2.17 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2018SP	7.49	9.66	2.17	28.9%
2026SP	7.55	9.72	2.17	28.8%

Table 5-2: 2018SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	13.9	0.49	7.9%
138	41.6	2.17	28.9%
345	19.1	0.06	0.4%
Max	**41.6**	**2.17**	**28.9%**

Table 5-3: 2026SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	13.8	0.49	7.7%
138	41.3	2.17	28.8%
345	19.1	0.06	0.4%
Max	**41.3**	**2.17**	**28.8%**

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-2016-118 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 91 x GE 2.82 MW (GEWTG2) + 12 x GE 2.5 MW (GEWTG2) configuration for the GEN-2016-118 generating facilities. This stability analysis was performed using PTI's PSS/E version 33.7 software.

The stability models were developed using the models from DISIS-2016-002 for Group 1. The modifications requested for the GEN-2016-118 project was used to create modified stability models for this impact study.

The modified dynamics model data for the DISIS-2016-002 Group 1 request, GEN-2016-118, 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-2016-118 and other equally and prior queued projects in Group 1. In addition, voltages of five (5) buses away from the POI of GEN-2016-118 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-2016-118 and selected additional fault events for GEN-2016-118 as required. The new set of faults were simulated using the modified study models. The fault events included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers. The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 2017 Winter Peak, 2018 Summer Peak, and the 2026 Summer Peak models.

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT01-3PH	P1	3 phase fault on DOVERSW4 138 kV (520882) to OKEENE 4 138 kV (521016) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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.
FLT02-3PH	P1	3 phase fault on DOVERSW4 138 kV (520882) to DOVERSW2 69 kV (520881) to DVRTERT 13.8 kV (521166) transformer CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line.
FLT03-3PH	P1	3 phase fault on DOVERSW4 138 kV (520882) to DOVER 4 138 kV (520879) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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.
FLT04-3PH	P1	3 phase fault on DOVERSW4 138 kV (520882) to NKNGFSH 138 kV (520603) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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	P1	3 phase fault on DOVERSW4 138 kV (520882) to HENESEY4 138 kV (514774) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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.
FLT06-3PH	P1	3 phase fault on OKEENE 4 138 kV (521016) to OKEENE 2 69 kV (521015) to OKENTERT 13.8 kV (521173) transformer CKT 1, near OKEENE 4. a. Apply fault at the OKEENE 4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line.
FLT07-3PH	P1	3 phase fault on TWNLAKE4 138 kV (521073) to CRESENT4 138 kV (515377) line CKT 1, near TWNLAKE4. a. Apply fault at the TWNLAKE4 138 kV 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.
FLT08-3PH	P1	3 phase fault on CEDRDAL4 138 kV (520848) to PIC4 138 kV (520425) line CKT 1, near CEDRDAL4. a. Apply fault at the CEDRDAL4 138 kV 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.
FLT09-3PH	P1	3 phase fault on TWNLAKE4 138 kV (521073) to CASHION4 138 kV (520847) line CKT 1, near TWNLAKE4. a. Apply fault at the TWNLAKE4 138 kV 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.
FLT11-SB	P4	**Stuck Breaker at DOVERSW4 (520882)** a. Apply single phase fault at the DOVERSW4 138 kV bus. b. Clear fault after 16 cycles and trip the following elements. - DOVERSW4 138 kV (520882) to DOVER 138 kV (520879) line CKT 1 - DOVERSW4 138 kV (520882) to NKNGFSH 138 kV (520603) line CKT 1
FLT12-SB	P4	**Stuck Breaker at DOVERSW4 (520882)** a. Apply single phase fault at the DOVERSW4 138 kV bus. b. Clear fault after 16 cycles and trip the following elements. - DOVERSW4 138 kV (520882) to DOVERSW2 69 kV (520881) to DVRTERT 13.8 kV (521166) transformer CKT 1 - DOVERSW4 138 kV (520882) to HENESEY4 138 kV (514774) line CKT 1

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT13-SB	P4	**Stuck Breaker at DOVERSW4 (520882)** a. Apply single phase fault at the DOVERSW4 138 kV bus. b. Clear fault after 16 cycles and trip the following elements. - DOVERSW4 138 kV (520882) to OKEENE 4 138 kV (521016) line CKT 1 - DOVERSW4 138 kV (520882) to HENESEY4 138 kV (514774) line CKT 1
FLT01-PO1	P6	**Prior Outage of DOVERSW4 138 kV (520882) to DOVERSW2 69 kV (520881) to DVRTERT 13.8 kV (521166) transformer CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to OKEENE 4 138 kV (521016) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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-PO2	P6	**Prior Outage of DOVERSW4 138 kV (520882) to DOVER 138 kV (520879) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to NKNGFSH 138 kV (520603) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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-PO3	P6	**Prior Outage of DOVERSW4 138 kV (520882) to OKEENE 4 138 kV (521016) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to HENESEY4 138 kV (514774) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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-PO3	P6	**Prior Outage of DOVERSW4 138 kV (520882) to OKEENE 4 138 kV (521016) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to DOVERSW2 69 kV (520881) to DVRTERT 13.8 kV (521166) transformer CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line.
FLT03-PO4	P6	**Prior Outage of DOVERSW4 138 kV (520882) to NKNGFSH 138 kV (520603) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to DOVER 4 138 kV (520879) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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.
FLT01-PO5	P6	**Prior Outage of DOVERSW4 138 kV (520882) to HENESEY4 138 kV (514774) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to OKEENE 4 138 kV (521016) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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.
FLT07-PO6	P6	**Prior Outage of WOODRNG4 138 kV (514714) to WOODRNG7 345 kV (514715) to WOODRNG1 13.8 kV (515770) transformer CKT 1;** 3 phase fault on TWNLAKE4 138 kV (521073) to CRESENT4 138 kV (515377) line CKT 1, near TWNLAKE4. a. Apply fault at the TWNLAKE4 138 kV 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-PO7	P6	**Prior Outage of CRESENT4 138 kV (515377) to TWNLAKE4 138 kV (521073) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to DOVER 4 138 kV (520879) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT04-PO7	P6	**Prior Outage of CRESENT4 138 kV (515377) to TWNLAKE4 138 kV (521073) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to NKNGFSH 138 kV (520603) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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-PO7	P6	**Prior Outage of CRESENT4 138 kV (515377) to TWNLAKE4 138 kV (521073) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to HENESEY4 138 kV (514774) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-3PH	P1	3 phase fault on DOVER 4 138 kV (520879) to TWNLAKE4 138 kV (521073) line CKT 1, near DOVER 4. a. Apply fault at the DOVER 4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on NKNGFSH 138 kV (520603) to EKNGFSH3 138 kV (520600) line CKT 1, near NKNGFSH. a. Apply fault at the NKNGFSH 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1	3 phase fault on EKNGFSH3 138 kV (520600) to REEDING2 138 kV (521037) line CKT 1, near EKNGFSH3. a. Apply fault at the EKNGFSH3 138 kV 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.
FLT9004-3PH	P1	3 phase fault on OKEENE 4 138 kV (521016) to CEDRDAL4 138 kV (520848) line CKT 1, near OKEENE 4. a. Apply fault at the OKEENE 4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on HENESEY4 138 kV (514774) to WAUKOMI4 138 kV (514710) line CKT 1, near HENESEY4. a. Apply fault at the HENESEY4 138 kV 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.
FLT9006-3PH	P1	3 phase fault on WAUKOMI4 138 kV (514710) to WAUKOTP4 138 kV (514711) line CKT 1, near WAUKOMI4. a. Apply fault at the WAUKOMI4 138 kV 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-PO1	P6	**Prior Outage of DOVERSW4 138 kV (520882) to DOVERSW2 69 kV (520881) to DVRTERT 13.8 kV (521166) transformer CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to DOVER 4 138 kV (520879) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT04-PO1	P6	**Prior Outage of DOVERSW4 138 kV (520882) to DOVERSW2 69 kV (520881) to DVRTERT 13.8 kV (521166) transformer CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to NKNGFSH 138 kV (520603) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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-PO1	P6	**Prior Outage of DOVERSW4 138 kV (520882) to DOVERSW2 69 kV (520881) to DVRTERT 13.8 kV (521166) transformer CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to HENESEY4 138 kV (514774) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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.
FLT07-PO1	P6	**Prior Outage of DOVERSW4 138 kV (520882) to DOVERSW2 69 kV (520881) to DVRTERT 13.8 kV (521166) transformer CKT 1;** 3 phase fault on TWNLAKE4 138 kV (521073) to CRESENT4 138 kV (515377) line CKT 1, near TWNLAKE4. a. Apply fault at the TWNLAKE4 138 kV 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.
FLT01-PO2	P6	**Prior Outage of DOVERSW4 138 kV (520882) to DOVER 138 kV (520879) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to OKEENE 4 138 kV (521016) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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-PO2	P6	**Prior Outage of DOVERSW4 138 kV (520882) to DOVER 138 kV (520879) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to DOVERSW2 69 kV (520881) to DVRTERT 13.8 kV (521166) transformer CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line.
FLT05-PO2	P6	**Prior Outage of DOVERSW4 138 kV (520882) to DOVER 138 kV (520879) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to HENESEY4 138 kV (514774) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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-PO3	P6	**Prior Outage of DOVERSW4 138 kV (520882) to OKEENE 4 138 kV (521016) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to DOVER 4 138 kV (520879) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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-PO3	P6	**Prior Outage of DOVERSW4 138 kV (520882) to OKEENE 4 138 kV (521016) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to NKNGFSH 138 kV (520603) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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.
FLT07-PO3	P6	**Prior Outage of DOVERSW4 138 kV (520882) to OKEENE 4 138 kV (521016) line CKT 1;** 3 phase fault on TWNLAKE4 138 kV (521073) to CRESENT4 138 kV (515377) line CKT 1, near TWNLAKE4. a. Apply fault at the TWNLAKE4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT01-PO4	P6	**Prior Outage of DOVERSW4 138 kV (520882) to NKNGFSH 138 kV (520603) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to OKEENE 4 138 kV (521016) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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-PO4	P6	**Prior Outage of DOVERSW4 138 kV (520882) to NKNGFSH 138 kV (520603) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to DOVERSW2 69 kV (520881) to DVRTERT 13.8 kV (521166) transformer CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line.
FLT05-PO4	P6	**Prior Outage of DOVERSW4 138 kV (520882) to NKNGFSH 138 kV (520603) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to HENESEY4 138 kV (514774) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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-PO5	P6	**Prior Outage of DOVERSW4 138 kV (520882) to HENESEY4 138 kV (514774) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to DOVERSW2 69 kV (520881) to DVRTERT 13.8 kV (521166) transformer CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line.
FLT03-PO5	P6	**Prior Outage of DOVERSW4 138 kV (520882) to HENESEY4 138 kV (514774) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to DOVER 3 138 kV (520879) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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-PO5	P6	**Prior Outage of DOVERSW4 138 kV (520882) to HENESEY4 138 kV (514774) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to NKNGFSH 138 kV (520603) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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.
FLT07-PO5	P6	**Prior Outage of DOVERSW4 138 kV (520882) to HENESEY4 138 kV (514774) line CKT 1;** 3 phase fault on TWNLAKE4 138 kV (521073) to CRESENT4 138 kV (515377) line CKT 1, near TWNLAKE4. a. Apply fault at the TWNLAKE4 138 kV 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.
FLT01-PO6	P6	**Prior Outage of WOODRNG4 138 kV (514714) to WOODRNG7 345 kV (514715) to WOODRNG1 13.8 kV (515770) transformer CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to OKEENE 4 138 kV (521016) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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-PO6	P6	**Prior Outage of WOODRNG4 138 kV (514714) to WOODRNG7 345 kV (514715) to WOODRNG1 13.8 kV (515770) transformer CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to DOVERSW2 69 kV (520881) to DVRTERT 13.8 kV (521166) transformer CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT01-PO7	P6	**Prior Outage of CRESENT4 138 kV (515377) to TWNLAKE4 138 kV (521073) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to OKEENE 4 138 kV (521016) line CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV 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-PO7	P6	**Prior Outage of TWNLAKE4 138 kV (521073) to CRESENT4 138 kV (515377) line CKT 1;** 3 phase fault on DOVERSW4 138 kV (520882) to DOVERSW2 69 kV (520881) to DVRTERT 13.8 kV (521166) transformer CKT 1, near DOVERSW4. a. Apply fault at the DOVERSW4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line.
FLT1001-SB	P4	**Stuck Breaker at DOVERSW4 (520882)** a. Apply single phase fault at the DOVERSW4 138 kV bus. b. Clear fault after 16 cycles and trip the following elements. - DOVERSW4 138 kV (520882) to DOVERSW2 69 kV (520881) to DVRTERT 13.8 kV (521166) transformer CKT 1 - DOVERSW4 138 kV (520882) to DOVER 138 kV (520879) line CKT 1
FLT1002-SB	P4	**Stuck Breaker at DOVERSW4 (520882)** a. Apply single phase fault at the DOVERSW4 138 kV bus. b. Clear fault after 16 cycles and trip the following elements. - DOVERSW4 138 kV (520882) to NKNGFSH 138 kV (520603) line CKT 1 - DOVERSW4 138 kV (520882) to OKEENE 4 138 kV (521016) line CKT 1
FLT1003-SB	P4	**Stuck Breaker at HENESEY4 (514774)** a. Apply single phase fault at the HENESEY4 138 kV bus. b. Clear fault after 16 cycles and trip the following elements. c. Trip the whole bus HENESEY4 (514774).
FLT1004-SB	P4	**Stuck Breaker at OKEENE4 (521016)** a. Apply single phase fault at the OKEENE4 138 kV bus. b. Clear fault after 16 cycles and trip the following elements. c. Trip the whole bus OKEENE4 (521016).
FLT1005-SB	P4	**Stuck Breaker at TWNLAKE4 (521073)** a. Apply single phase fault at the TWNLAKE4 138 kV bus. b. Clear fault after 16 cycles and trip the following elements. c. Trip the whole bus TWNLAKE4 (521073).

6.3 Results

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

Table 6-2: GEN-2016-118 Dynamic Stability Results

Fault ID	17WP			18SP			26SP		
	Volt. Recovery	Volt. Violation	Stable	Volt. Recovery	Volt. Violation	Stable	Volt. Recovery	Volt. Violation	Stable
FLT01-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-3PH	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
FLT07-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT08-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT09-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	17WP			18SP			26SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT11-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT12-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT13-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT01-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT01-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT01-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT01-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT01-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT01-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

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

7.0 Material Modification Determination

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

7.1 Results

SPP determined the requested modification is not a Material Modification based on the results of this Modification Request Impact Study performed by Aneden. Aneden evaluated the impact of the requested modification on the prior study results. Aneden determined that the requested modification resulted in similar dynamic stability and short circuit analyses and that the prior study power flow results are not negatively impacted.

This determination implies that any network upgrades already required by GEN-2016-118 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.

8.0 Conclusions

The Interconnection Customer for GEN-2016-118 requested a Modification Request Impact Study to assess the impact of the turbine and facility changes to a configuration with a total of 91 x GE 2.82 MW + 12 x GE 2.5 MW wind turbines for total capacity of 286.62 MW. In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformer, and the generation interconnection line.

SPP determined that power flow should not be performed based on the POI MW injection decrease of 1.53%. However, SPP determined that the turbine change from Vestas to GE turbines required short circuit and dynamic stability analyses.

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

The results of the charging current compensation analysis performed using the 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak models showed that the GEN-2016-118 project needed 18.84 MVAr of reactor shunts on the 34.5 kV bus of the project substation, an increase from the 16.36 MVAr found in the pre-modification case. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the customer and Transmission Owner. SPP does not require additional reactive requirements based on the results of this analysis.

The results from the short circuit analysis with the updated topology showed that the maximum GEN-2016-118 contribution to three-phase fault currents in the immediate systems at or near GEN-2016-118 was not greater than 2.17 kA for the 2018SP and 2026SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-118 generators online were below 42 kA for the 2018SP and 2026SP models.

The dynamic stability analysis was performed using the three DISIS-2016-002 models 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak. Up to 54 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

The results of the dynamic stability analysis showed that there were no damping or voltage recovery violations observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

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.

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.