Report on

GEN-2016-095 Modification Request Impact Study

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Southwest Power Pool

SPP Southwest Power Pool

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
10/17/2022	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-2016-095, an active Generation Interconnection Request (GIR) with a point of interconnection (POI) at the G16-091-TAP 345 kV bus on the Gracemont to Lawton East Side 345 kV line.

The GEN-2016-095 project interconnects in the American Electric Power West (AEPW) control area with a capacity of 200 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2016-095 to change the turbine configuration to 33 x Vestas V162 6.0 MW + 1 x Vestas V136 3.45 MW for a total capacity of 201.45 MW. The generating capacity for GEN-2016-095 exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 200 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. The existing and modified configurations for GEN-2016-095 are shown in Table ES-2.

Table ES-1: GEN-2016-095 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2016-095	Tap on Gracemont 345 kV (515800) to L.E.S. 345 kV (511468) (G16-091-TAP 587744)	100 x Vestas V110 2.0 MW	200

Table ES-2: GEN-2016-095 Modification Request

Facility	Existing Configuration	Modification Configuration	
Point of Interconnection	Tap on Gracemont 345 kV (515800) to L.E.S. 345 kV (511468) (G16-091-TAP 587744)	Tap on Gracemont 345 kV (515800) to L.E.S. 345 kV (511468) (G16-091-TAP 587744)	
Configuration/Capacity	100 x Vestas V110 2.0 MW = 200 MW	33 x Vestas V162 6.0 MW + 1 x Vestas V136 3.45 MW = 201.45 MW POI limited to 200 MW	
Generation Interconnection Line	Length = 7 miles R = 0.000679 pu X = 0.004582 pu B = 0.043909 pu Rating MVA = 0 MVA[4]	Length = 7.67 miles R = 0.000390 pu X = 0.000330 pu B = 0.054060 pu Rating MVA = 809 MVA	
Main Substation Transformer[1]	X = 8.997%, R = 0.225%, Winding MVA = 132 MVA, Rating MVA = 220 MVA	X = 9.998%, R = 0.211%, Winding MVA = 138 MVA, Rating [A/B] MVA = 138/230 MVA	
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 100 X = 9.759%, R = 0.895%, Winding MVA = 230 MVA, Rating MVA = 230 MVA	Gen 1 Equivalent Qty: 33 X = 10.299%, R = 0.9%, Winding MVA = 240.9 MVA, Rating MVA = 240.9 MVA	Gen 2 Equivalent Qty: 1 X = 8.999%, R = 0.8%, Winding MVA = 4.0 MVA, Rating MVA = 4.0 MVA
Equivalent Collector Line[2]	R = 0.006310 pu X = 0.005700 pu B = 0.080050 pu	R = 0.003020 pu X = 0.004132 pu B = 0.053287 pu	
Generator Dynamic Model[3] & Power Factor	100 x Vestas V110 2.0 MW (VWCO81)[3] Leading and Lagging: ±1.0	33 x Vestas V162 6.0 MW (EV211460000)[3] Leading: 0.949 Lagging: 0.914	1 x Vestas V136 3.45 MW (CP200660000)[3] Leading: 0.932 Lagging: 0.89

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

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.15% compared to the DISIS-2017-001 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, Vestas, the change in stability model from VWCO81 to EV211460000 and CP200660000 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 study models:

1. 2019 Winter Peak (19WP),
2. 2021 Light Load (21LL),
3. 2021 Summer Peak (21SP),
4. 2028 Summer Peak (28SP)

Aneden reviewed the GIRs that shared the same POI, G16-091-TAP 345 kV bus, and updated as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the GEN-2016-091 project configuration in the base model.

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-2016-095 project needed 10.75 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 12.4 MVAr found for the existing GEN-2016-095 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 topology showed that the maximum GEN-2016-095 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2016-095 POI was no greater than 0.43 kA for the 21SP and 28SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-095 generators online were below 45 kA for the 21SP and 28SP models. There were several buses with a maximum fault current of over 40 kA. These buses are highlighted in Appendix B.

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 42 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

The results of the stability analysis showed that oscillations were observed for the TOLK unit 1 at bus 525561 with FLT9013-3PH (loss of the G16-091-TAP to GEN-2016-091 345 kV line) in the 21LL model. Similar oscillations were also observed in the DISIS-2017-001 case without the GEN-2016-095 modification. As such, these oscillations were not attributed to the GEN-2016-095 modification request.

There were no other damping or voltage recovery violations attributed to the GEN-2016-095 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-2016-095. 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 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 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

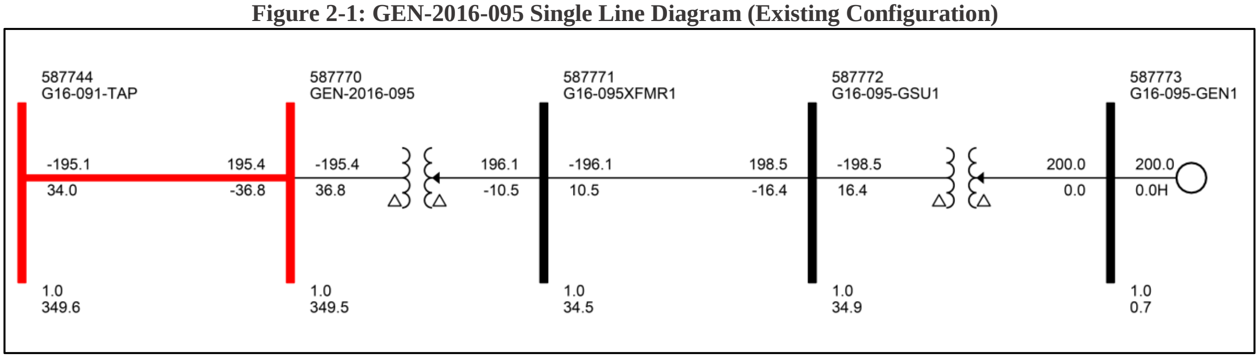
The GEN-2016-095 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the G16-091-TAP 345 kV bus on the Gracemont to Lawton East Side 345 kV line. At the time of the posting of this report, GEN-2016-095 is an active Interconnection Request with a queue status of "IA FULLY EXECUTED/ON SCHEDULE." GEN-2016-095 is a wind farm with maximum summer and winter queue capacity of 200 MW with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS) requests.

The GEN-2016-095 project is currently in the DISIS-2016-002 cluster. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2016-095 configuration. The GEN-2016-095 project interconnects in the American Electric Power West (AEPW) control area with a capacity of 200 MW as shown in Table 2-1 below.

Table 2-1: GEN-2016-095 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2016-095	Tap on Gracemont 345 kV (515800) to L.E.S. 345 kV (511468) (G16-091-TAP 587744)	100 x Vestas V110 2.0 MW	200

Figure 2-1: GEN-2016-095 Single Line Diagram (Existing Configuration)



This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2016-095 to a turbine configuration of 33 x Vestas V162 6.0 MW + 1 x Vestas V136 3.45 MW for a total capacity of 201.45 MW. The combined generating capacity for GEN-2016-095 (201.45 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, (200 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-2016-095 modification. The existing and modified configurations for GEN-2016-095 are shown in Table 2-2.

Figure 2-2: GEN-2016-095 Single Line Diagram (Modification Configuration)

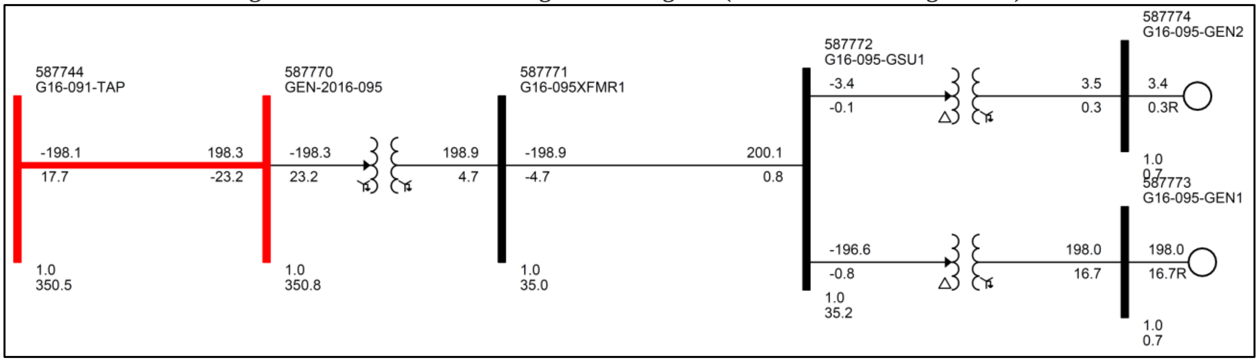


Table 2-2: GEN-2016-095 Modification Request

Facility	Existing Configuration	Modification Configuration	
Point of Interconnection	Tap on Gracemont 345 kV (515800) to L.E.S. 345 kV (511468) (G16-091-TAP 587744)	Tap on Gracemont 345 kV (515800) to L.E.S. 345 kV (511468) (G16-091-TAP 587744)	
Configuration/Capacity	100 x Vestas V110 2.0 MW = 200 MW	33 x Vestas V162 6.0 MW + 1 x Vestas V136 3.45 MW = 201.45 MW POI limited to 200 MW	
Generation Interconnection Line	Length = 7 miles R = 0.000679 pu X = 0.004582 pu B = 0.043909 pu Rating MVA = 0 MVA[4]	Length = 7.67 miles R = 0.000390 pu X = 0.000330 pu B = 0.054060 pu Rating MVA = 809 MVA	
Main Substation Transformer[1]	X = 8.997%, R = 0.225%, Winding MVA = 132 MVA, Rating MVA = 220 MVA	X = 9.998%, R = 0.211%, Winding MVA = 138 MVA, Rating [A/B] MVA = 138/230 MVA	
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 100 X = 9.759%, R = 0.895%, Winding MVA = 230 MVA, Rating MVA = 230 MVA	Gen 1 Equivalent Qty: 33 X = 10.299%, R = 0.9%, Winding MVA = 240.9 MVA, Rating MVA = 240.9 MVA	Gen 2 Equivalent Qty: 1 X = 8.999%, R = 0.8%, Winding MVA = 4.0 MVA, Rating MVA = 4.0 MVA
Equivalent Collector Line[2]	R = 0.006310 pu X = 0.005700 pu B = 0.080050 pu	R = 0.003020 pu X = 0.004132 pu B = 0.053287 pu	
Generator Dynamic Model[3] & Power Factor	100 x Vestas V110 2.0 MW (VWCO81)[3] Leading and Lagging: ±1.0	33 x Vestas V162 6.0 MW (EV211460000)[3] Leading: 0.949 Lagging: 0.914	1 x Vestas V136 3.45 MW (CP200660000)[3] Leading: 0.932 Lagging: 0.89

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

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 the GIRs that shared the same POI, G16-091-TAP 345 kV bus, and updated as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the GEN-2016-091 project configuration in the base model.

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 modifications for GEN-2016-095. The percentage change in the POI injection was then evaluated. 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 (increase of 0.15%) 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-2016-095 POI Injection Comparison

Interconnection Request	Existing POI Injection (MW)	MRIS POI Injection (MW)	POI Injection Difference %
GEN-2016-095	197.8	198.1	0.15%

3.2 Turbine Parameters Comparison

SPP determined that while the modification used the same turbine manufacturer, Vestas, the change in stability model from VWCO81 to EV211460000 and CP200660000 required short circuit and dynamic stability analysis. 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 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 stability model 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-2016-095 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-2016-095 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 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).

Aneden performed the charging current compensation analysis using the modification request data based on the DISIS 2017-001 stability study models:

1. 2019 Winter Peak (19WP),
2. 2021 Light Load (21LL),
3. 2021 Summer Peak (21SP),
4. 2028 Summer Peak (28SP)

4.2 Results

The results from the analysis showed that the GEN-2016-095 project needed approximately 10.75 MVAr of compensation at its project substation, to reduce the POI MVAr to zero. This is a decrease from the 12.4 MVAr found for the existing GEN-2016-095 configuration calculated using the DISIS-2017-001 models. 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 topology. The final shunt reactor requirements for GEN-2016-095 are shown in Table 4-1.

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-2016-095	587744	G16-091-TAP 345 kV	10.75	10.75	10.75	10.75

Figure 4-1: GEN-2016-095 Single Line Diagram (Existing Shunt Reactor)

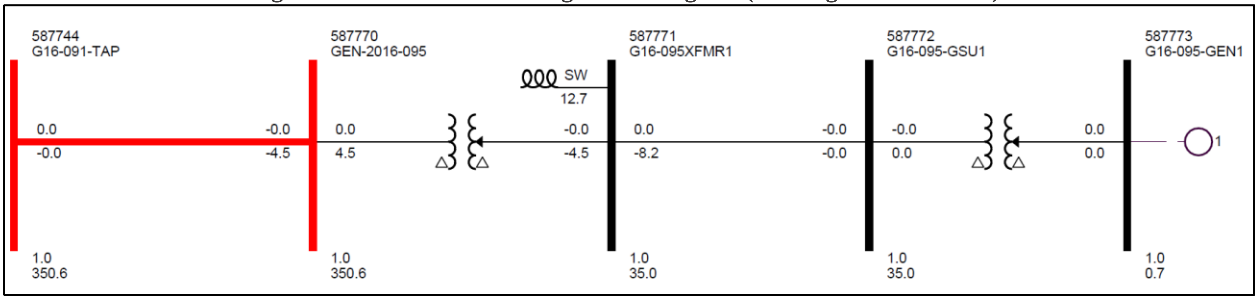
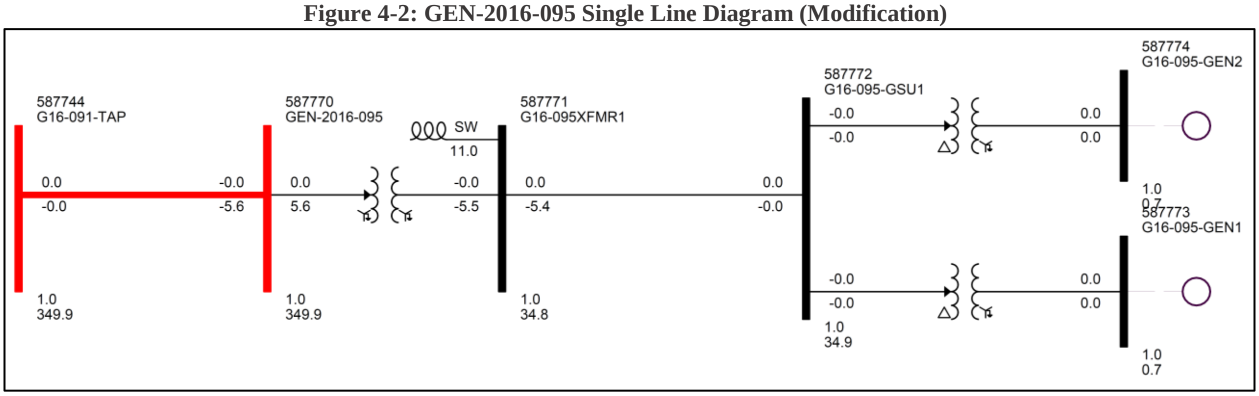


Figure 4-2: GEN-2016-095 Single Line Diagram (Modification)



5.0 Short Circuit Analysis

A short circuit study was performed using the 21SP and 28SP models for GEN-2016-095. 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-2016-095 online.

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

1. 2021 Summer Peak (21SP),
2. 2028 Summer Peak (28SP)

5.2 Results

The results of the short circuit analysis for the 21SP and 28SP models are summarized in Table 5-1 through Table 5-3 respectively. The GEN-2016-095 POI bus (G16-091-TAP 345 kV - 587744) fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 14.46 kA with the GEN-2016-095 project online.

The maximum fault current calculated within 5 buses of the GEN-2016-095 POI was less than 45 kA for the 21SP and 28SP models respectively. There were several buses with a maximum fault current of over 40 kA. These buses are highlighted in Appendix B. The maximum GEN-2016-095 contribution to three-phase fault current was about 3.1% and 0.43 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
21SP	13.81	14.24	0.43	3.1%
28SP	14.02	14.46	0.43	3.1%

Table 5-2: 21SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	16.5	0.02	0.1%
115	19.4	0.00	0.0%
138	44.5	0.12	0.5%
230	26.7	0.01	0.1%
345	34.5	0.43	3.1%
Max	**44.5**	**0.43**	**3.1%**

Table 5-3: 28SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	19.7	0.02	0.1%
115	19.2	0.00	0.0%
138	44.3	0.12	0.5%
230	25.1	0.01	0.1%
345	34.5	0.43	3.1%
Max	**44.3**	**0.43**	**3.1%**

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-2016-095 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-2016-095 configuration of 33 x Vestas V162 6.0 MW (EV211460000) + 1 x Vestas V136 3.45 MW (CP200660000). This stability analysis was performed using PTI's PSS/E version 33.10 software.

The modifications requested for the GEN-2016-095 project were used to create modified stability model**s** for this impact study based on the DISIS 2017-001 stability study models:

1. 2019 Winter Peak (19WP),
2. 2021 Light Load (21LL),
3. 2021 Summer Peak (21SP),
4. 2028 Summer Peak (28SP)

Aneden reviewed the GIRs that shared the same POI, G16-091-TAP 345 kV bus, and updated as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the GEN-2016-091 project configuration in the base model.

The modified dynamics model data for the GEN-2016-095 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.

There were some modifications made to the starting DISIS-2017-001 models consistent with the DISIS-2017-001 Phase 2 Stability results:

1. 520519 (BCI WTG), 520520 (BCII WTG), & 520522 (BCVI_WTG1) had abnormal oscillations under numerous contingencies across all cases. This was identified as a potential modeling issue. Since this issue was observed in many contingencies, the BC units (520519, 520520, 520521, 520522) were GNET and no further issues were observed.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2016-095 and other equally and prior queued projects in their cluster group[1]. In addition, voltages of five (5) buses away from the POI of GEN-2016-095 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 520 (AEPW), 524 (OKGE), 525 (WFEC), 526 (SPS), 531 (MIDW), 534 (SUNC), and 536 (WERE) were monitored. In addition, the voltages of all 100 kV and above buses within the study areas were monitored.

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

6.2 Fault Definitions

Aneden simulated the faults previously simulated for GEN-2016-095 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.

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT09-3PH	P1	3 phase fault on the O.K.U.-7 (511456) to TUCO_INT (525832) 345 kV line CKT 1, near O.K.U.-7. a. Apply fault at the O.K.U.-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.
FLT14-3PH	P1	3 phase fault on the L.E.S.-4 138 kV (511467) / 345 kV (511468)/ 13.8 kV (511411) XFMR CKT 2, near L.E.S. -4 138 kV. a. Apply fault at the L.E.S. -4 138 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT15-3PH	P1	3 phase fault on the L.E.S.-7 (511468) to O.K.U.-7 (511456) 345 kV line CKT 1, near L.E.S.-7. a. Apply fault at the L.E.S.-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.
FLT16-3PH	P1	3 phase fault on the L.E.S.-7 (511468) to TERRYRD7 (511568) 345 kV line CKT 1, near L.E.S.-7. a. Apply fault at the L.E.S.-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.
FLT26-3PH	P1	3 phase fault on the TERRYRD7 (511568) to SUNNYSD7 (515136) 345 kV line CKT 1, near TERRYRD7. a. Apply fault at the TERRYRD7 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.
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 the GRACMNT 345kV (515800) / 138kV (515802) / 13.8kV (515801) XFMR CKT 1, near GRACMNT 345kV. a. Apply fault at the GRACMNT 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.
FLT35-3PH	P1	3 phase fault on the GRACMNT4 (515802) to ANADARK4 (520814) 138 kV line CKT 1, near GRACMNT4. a. Apply fault at the GRACMNT4 138 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.
FLT47-3PH	P1	3 phase fault on the G16-037-TAP 7 (560078) to GRACMNT7 (515800) 345 kV line CKT 1, near G16-037-TAP 7. a. Apply fault at the G16-037-TAP 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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
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.
FLT52-3PH	P1	3 phase fault on the TUCO_INT (525832) to O.K.U.-7 (511456) 345 kV line CKT 1, near TUCO_INT. a. Apply fault at the TUCO_INT 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.
FLT64-3PH	P1	3 phase fault on the TERRYRD7 (511568) to L.E.S.-7 (511468) 345 kV line CKT 1, near TERRYRD7. a. Apply fault at the TERRYRD7 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.
FLT33-PO2	P6	PRIOR OUTAGE of G16-091-TAP (587744) to L.E.S.-7 (511468) 345 kV line CKT 1 3 phase fault on the GRACMNT 345kV (515800) / 138kV (515802) / 13.8kV (515801) XFMR CKT 1, near GRACMNT 345kV. a. Apply fault at the GRACMNT 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT34-PO2	P6	PRIOR OUTAGE of G16-091-TAP (587744) to L.E.S.-7 (511468) 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.
FLT9001-3PH	P1	3 phase fault on the G16-091-TAP (587744) to GRACMNT7 (515800) 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.
FLT9002-3PH	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-GEN1 (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.
FLT9003-3PH	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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9004-3PH	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 MNCOWNG1 (515921) Trip generator G15-057-GEN1 (584953) Trip generator G15-057-GEN2 (584954) Trip generator G15-057-GEN3 (584955) Trip generator MNCO4G11 (515943) Trip generator G14-056-GEN2 (584064) Trip generator G14-056-GEN3 (584067) 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 G16-037-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.
FLT9006-3PH	P1	3 phase fault on the G16-037-TAP (560078) to GEN-2016-037 (587230) 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. Trip generator G16-037-GEN1 (587233) 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 L.E.S.-4 345 kV (511468)/ 138 kV (511467) /13.8 kV (511414) XFMR CKT 1, near L.E.S. -4 345 kV. a. Apply fault at the L.E.S. -4 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9008-3PH	P1	3 phase fault on the TERRYRD7 (511568) to RUSHSPR7 (511571) 345 kV line CKT 1, near TERRYRD7. a. Apply fault at the TERRYRD7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator G14-057-GEN1 (584073) Trip generator G15-092-GEN1 (563262) Trip generator G15-092-GEN2 (563263) Trip generator G15-045-GEN1 (584862) 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.
FLT9009-3PH	P1	3 phase fault on the GRACMNT7 (515800) to G16-037-TAP 7 (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.
FLT9010-3PH	P1	3 phase fault on the O.K.U.-7 (511456) to OKLAUN 7 (599891) 345 kV DCLINE, near O.K.U.-7. a. Apply fault at the O.K.U.-7 345 kV bus. b. Block DCLINE SPP_44_OKLUN
FLT9011-3PH	P1	3 phase fault on the O.K.U.-7 (511456) to GEN-2017-033 (588760) 345 kV line CKT 1, near O.K.U.-7. a. Apply fault at the O.K.U.-7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator G17-033-GEN1 (588763) Trip generator G17-033-GEN2 (588767) 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.
FLT9012-3PH	P1	3 phase fault on the O.K.U.-7 (511456) to OKLAUN HVDC7 (511565) 345 kV line CKT 1, near O.K.U.-7. a. Apply fault at the O.K.U.-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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9013-3PH	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 generators G16-091-GEN1 (587743), G16-091-GEN2 (587749), G16-091-GEN3 (587747), G16-091-GEN4 (587748). 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.
FLT15-PO1	P6	PRIOR OUTAGE of G16-091-TAP (587744) to GRACMNT7 (515800) 345 kV line CKT 1 3 phase fault on the L.E.S.-7 (511468) to O.K.U.-7 (511456) 345 kV line CKT 1, near L.E.S.-7. a. Apply fault at the L.E.S.-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.
FLT16-PO1	P6	PRIOR OUTAGE of G16-091-TAP (587744) to GRACMNT7 (515800) 345 kV line CKT 1 3 phase fault on the L.E.S.-7 (511468) to TERRYRD7 (511568) 345 kV line CKT 1, near L.E.S.-7. a. Apply fault at the L.E.S.-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.
FLT9007-PO1	P6	PRIOR OUTAGE of G16-091-TAP (587744) to GRACMNT7 (515800) 345 kV line CKT 1 3 phase fault on the L.E.S.-4 345 kV (511468)/ 138 kV (511467) /13.8 kV (511411) XFMR CKT 1, near L.E.S. -4 345 kV. a. Apply fault at the L.E.S. -4 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9002-PO2	P6	PRIOR OUTAGE of G16-091-TAP (587744) to L.E.S.-7 (511468) 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-GEN1 (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.
FLT9009-PO2	P6	PRIOR OUTAGE of G16-091-TAP (587744) to L.E.S.-7 (511468) 345 kV line CKT 1 3 phase fault on the GRACMNT7 (515800) to G16-037-TAP 7 (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.
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) XFMR 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 MINCO 7 (514801) 345 kV line CKT 1.
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) XFMR CKT 1.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1005-SB	P4	Stuck Breaker on L.E.S.-7 (511468) 345kV bus. a. Apply single-phase fault at L.E.S.-7 (511468) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the L.E.S.-7 (511468) to G16-091-TAP (587744) 345 kV line CKT 1. d. Trip the L.E.S.-4 345 kV (511468)/ 138 kV (511467) /13.8 kV (511414) XFMR CKT 1.
FLT1006-SB	P4	Stuck Breaker on L.E.S.-7 (511468) 345kV bus. a. Apply single-phase fault at L.E.S.-7 (511468) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the L.E.S.-7 (511468) to TERRYRD7 (511568) 345 kV line CKT 1. d. Trip the L.E.S.-7 (511468) to O.K.U.-7 (511456) 345 kV line CKT 1.
FLT1007-SB	P4	Stuck Breaker on L.E.S.-7 (511468) 345kV bus. a. Apply single-phase fault at L.E.S.-7 (511468) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the L.E.S.-7 (511468) to O.K.U.-7 (511456) 345 kV line CKT 1. d. Trip the L.E.S.-4 345 kV (511468)/ 138 kV (511467) /13.8 kV (511414) XFMR CKT 1.

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-2016-095 Dynamic Stability Results

Fault ID	19WP			21LL			21SP			28SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT09-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT14-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT15-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT16-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT26-3PH	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
FLT35-3PH	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
FLT52-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT64-3PH	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
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	19WP			21LL			21SP			28SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	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
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT15-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT16-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-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
FLT33-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT34-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

The results of the stability analysis showed that oscillations were observed for the TOLK unit 1 at bus 525561 with FLT9013-3PH (loss of the G16-091-TAP to GEN-2016-091 345 kV line) in the 21LL model. Similar oscillations were also observed in the starting DISIS-2017-001 TC case without the GEN-2016-095 modification as shown Figure 6-1 below and with the GEN-2016-095 modification as shown Figure 6-2. Therefore, the oscillations are not attributed to the GEN-2016-095 modification request.

Figure 6-1: FLT9013-3PH TOLK Unit 1 Oscillation (21LL DISIS Case)

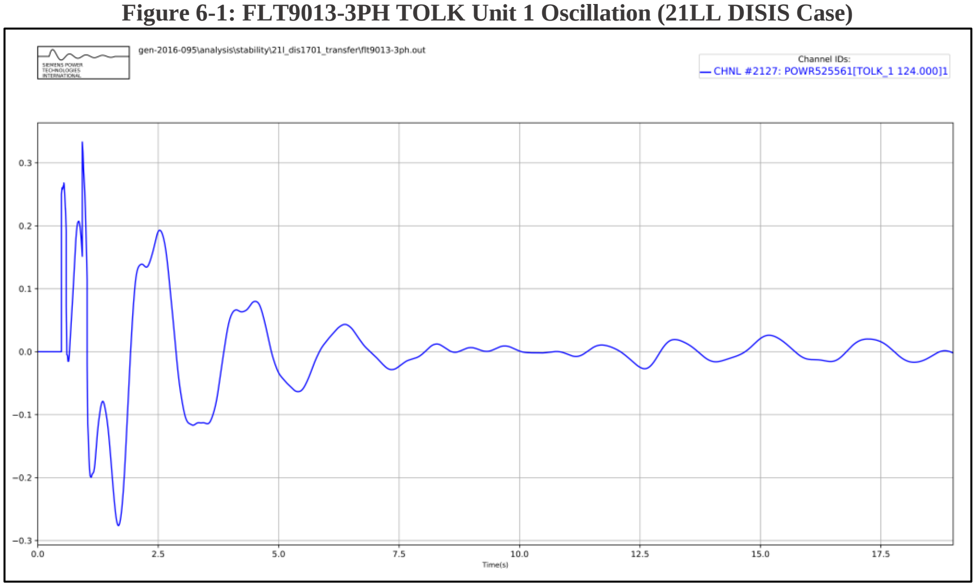
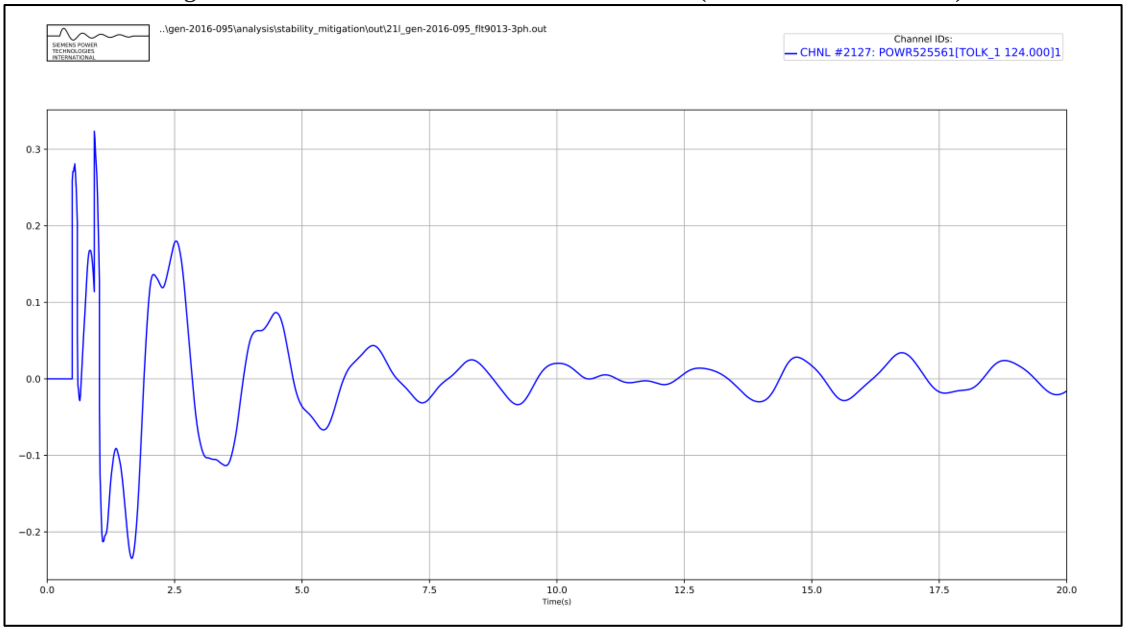


Figure 6-2: FLT9013-3PH TOLK Unit 1 Oscillation (21LL Modification Case)



There were no other damping or voltage recovery violations attributed to the GEN-2016-095 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 which is 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-2016-095 (201.45 MW) exceeds the GIA Interconnection Service amount, (200 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 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.

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-2016-095 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-2016-095 requested a Modification Request Impact Study to assess the impact of the turbine and facility change to 33 x Vestas V162 6.0 MW + 1 x Vestas V136 3.45 MW for a total capacity of 201.45 MW. The combined generating capacity of GEN-2016-095 (201.45 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 200 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.

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.15% compared to the DISIS-2017-001 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, Vestas, the change in stability model from VWCO81 to EV211460000 and CP200660000 required short circuit and dynamic stability analyses.

Aneden reviewed the GIRs that shared the same POI, G16-091-TAP 345 kV, and updated as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the GEN-2016-091 project configuration 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-2016-095 project needed 10.75 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 12.4 MVAr found for the existing GEN-2016-095 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 topology showed that the maximum GEN-2016-095 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2016-095 POI was not greater than 0.43 kA for the 21SP and 28SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-095 generators online were below 45 kA for the 21SP and 28SP models. There were several buses with a maximum fault current of over 40 kA. These buses are highlighted in Appendix B.

The dynamic stability analysis was performed using the four modified study models, 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak. Up to 42 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

The results of the stability analysis showed that oscillations were observed for the TOLK unit 1 at bus 525561 with FLT9013-3PH (loss of the G16-091-TAP to GEN-2016-091 345 kV line) in the 21LL model.

Similar oscillations were also observed in the DISIS-2017-001 case without the GEN-2016-095 modification. As such, these oscillations were not attributed to the GEN-2016-095 modification request.

There were no other damping or voltage recovery violations attributed to the GEN-2016-095 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.