Submitted to
Southwest Power Pool

Report On

GEN-2008-079 Modification Request Impact Study

Revision R1

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anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
10/26/2021	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-2008-079, an active Generation Interconnection Request (GIR) with a point of interconnection (POI) at the Crooked Creek 115 kV Substation.

The GEN-2008-079 project is proposed to interconnect in the Mid-Kansas Electric Company, Inc (MKEC) control area with a capacity of 98.9 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2008-079 to change the turbine configuration to 12 x Siemens 2.3 MW + 28 x Siemens 2.66 MW + 3 x GE 2.3 MW for a total generating capacity of 108.98 MW. The generating capacity for GEN-2008-079 (108.98 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, 98.9 MW, as listed in Appendix A. The customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

In addition, the modification request included changes to the collection system, generator step-up transformers, reactive power devices, and main substation transformer. The existing and modified configurations for GEN-2008-079 are shown in Table ES-2.

Table ES-1: GEN-2008-079 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2008-079	Crooked Creek 115 kV (539783)	43 x Siemens 2.3 MW	98.9

Table ES-2: GEN-2008-079 Modification Request

<table>
<tr><th>Facility</th><th>Existing</th><th colspan="3">Modification</th></tr>
<tr><td>Point of Interconnection</td><td>Crooked Creek 115 kV (539783)</td><td colspan="3">Crooked Creek 115 kV (539783)</td></tr>
<tr><td>Configuration/Capacity</td><td>43 x Siemens 2.3 MW = 98.9 MW</td><td colspan="3">12 x Siemens 2.3 MW + 28 x Siemens 2.66 MW + 3 x GE 2.3 MW = 108.98 MW
PPC to limit POI to 98.9 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td>Length = 10 miles
R = 0.008900 pu
X = 0.056400 pu
B = 0.007600 pu
Rating A MVA = 155 MVA, Rating B MVA = 190 MVA</td><td colspan="3">Length = 10 miles
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<tr><td>Main Substation Transformer[1]</td><td>X12 = 12.708% R12 = 0.357%, X23 = 20.387% R23 = 0.58%, X13 = 5.548% R13 = 0.159%,
Winding MVA = 100 MVA,
Winding 1 & 2 Rating MVA = 112 MVA,
Winding 3 Rating MVA = 50 MVA</td><td colspan="3">X = 8.007% R = 0.233%,
Winding MVA = 67.2 MVA,
Rating MVA = 112 MVA</td></tr>
<tr><td>Equivalent GSU Transformer[1]</td><td>Gen 1 Equivalent Qty: 43:
X = 6.0% R = 0.84%,
Winding MVA = 111.8 MVA,
Rating MVA = 111.8 MVA</td><td>Gen 1 Equivalent Qty: 12:
X = 5.947%, R = 0.793%,
Winding MVA = 31.2 MVA,
Rating MVA = 31.2 MVA</td><td>Gen 2 Equivalent Qty: 28:
X = 5.947%, R = 0.793%, Winding MVA = 90.776 MVA,
Rating MVA[2] = 90.8 MVA</td><td>Gen 3 Equivalent Qty: 3:
X = 5.947%, R = 0.793%, Winding MVA = 7.8 MVA,
Rating MVA = 7.8 MVA</td></tr>
<tr><td>Equivalent Collector Line[3]</td><td>R = 0.007460 pu
X = 0.006920 pu
B = 0.038000 pu</td><td colspan="3">R = 0.007405 pu
X = 0.008044 pu
B = 0.036354 pu</td></tr>
<tr><td>Reactive Power Devices</td><td>3 x 5 MVAR 34.5 kV Capacitor Bank</td><td colspan="3">2 x 15 MVAR 115 kV Capacitor Bank</td></tr>
</table>

1) X/R based on Winding MVA, 2) Rating rounded in PSS/E, 3) all pu are on 100 MVA Base

SPP determined that power flow should not be performed based on the POI MW injection increase of 2.60% compared to the DISIS-2017-001 power flow models. However, SPP determined that the turbine change from Siemens to a combination of Siemens and GE turbines, the project capacity increase, and the use of a PPC 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 Group 3 study models:

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

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-2008-079 project needed 4.4 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 4.6 MVAr found for the existing GEN-2008-079 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-2008-079 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2008-079 POI was no greater than 0.90 kA for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2008-079 generators online were below 14 kA for the 2021SP and 2028SP models.

The dynamic stability analysis was performed using PTI PSS/E version 33.10 software and the four modified study models, 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak. Up to 35 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 dynamic stability analysis showed that there were no damping or voltage recovery violations attributed to the GEN-2008-079 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-2008-079. 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

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 included if the difference has a significant impact on the results of the 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 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-2008-079 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the Crooked Creek 115 kV Substation. At the time of the posting of this report, GEN-2008-079 is an active Interconnection Request with a queue status of "IA FULLY EXECUTED/COMMERCIAL OPERATION." GEN-2008-079 is a wind farm and has a maximum summer and winter queue capacity of 98.9 MW with Energy Resource Interconnection Service (ERIS).

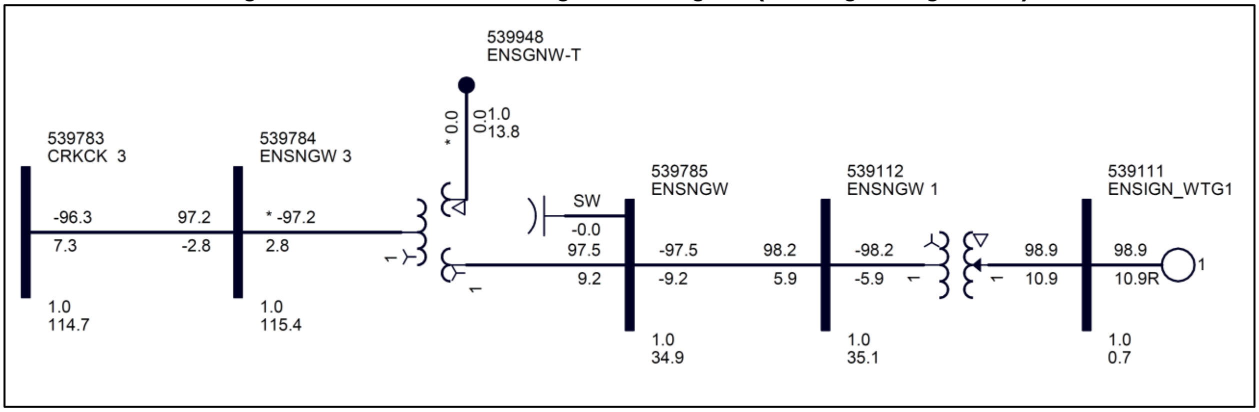
The GEN-2008-079 project was originally studied in the DISIS-2009-001 study. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2008-079 configuration.

The GEN-2008-079 project is proposed to interconnect in the Mid-Kansas Electric Company, Inc (MKEC) control area with a capacity of 98.9 MW as shown in Table 2-1 below.

Table 2-1: GEN-2008-079 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2008-079	Crooked Creek 115 kV (539783)	43 x Siemens 2.3 MW	98.9

Figure 2-1: GEN-2008-079 Single Line Diagram (Existing Configuration)



This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2008-079 to change the turbine configuration to 12 x Siemens 2.3 MW + 28 x Siemens 2.66 MW + 3 x GE 2.3 MW for a total generating capacity of 108.98 MW. The generating capacity for GEN-2008-079 (108.98 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, 98.9 MW, as listed in Appendix A. The customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

In addition, the modification request included changes to the collection system, generator step-up transformers, reactive power devices, and main substation transformer. Figure 2-2 shows the power flow model single line diagram for the GEN-2008-079 modification. The existing and modified configurations for GEN-2008-079 are shown in Table 2-2.

Figure 2-2: GEN-2008-079 Single Line Diagram (Modification Configuration)

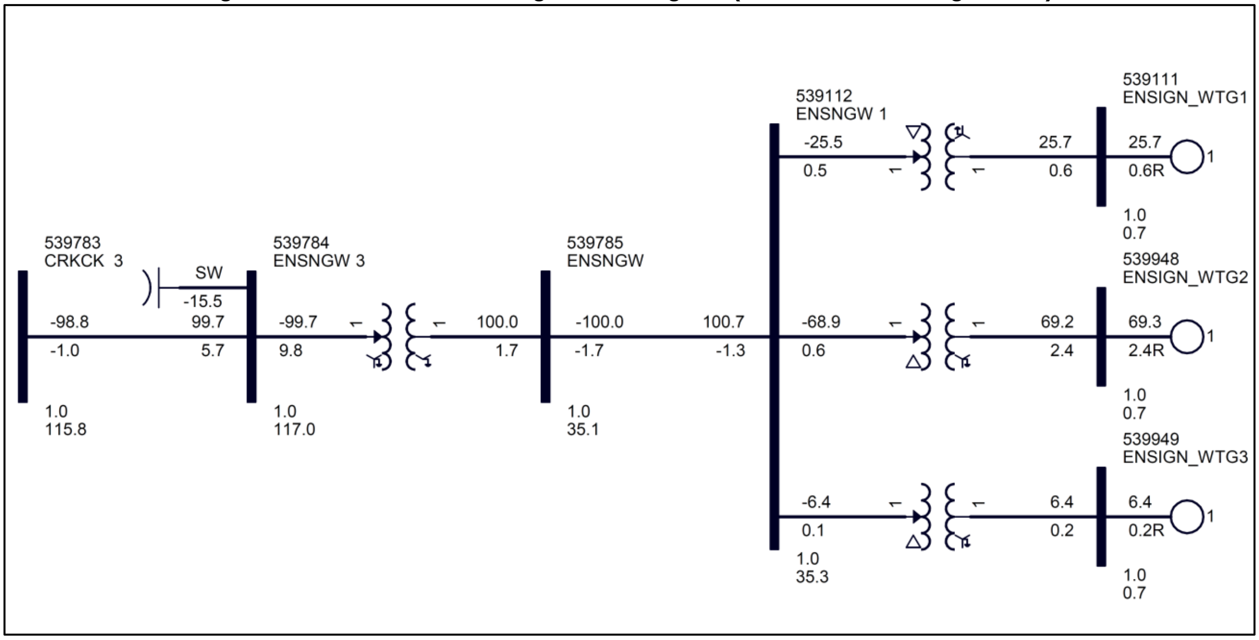


Table 2-2: GEN-2008-079 Modification Request

Facility	Existing	Modification		
Point of Interconnection	Crooked Creek 115 kV (539783)	Crooked Creek 115 kV (539783)		
Configuration/Capacity	43 x Siemens 2.3 MW = 98.9 MW	12 x Siemens 2.3 MW + 28 x Siemens 2.66 MW + 3 x GE 2.3 MW = 108.98 MW PPC to limit POI to 98.9 MW		
Generation Interconnection Line	Length = 10 miles R = 0.008900 pu X = 0.056400 pu B = 0.007600 pu Rating A MVA = 155 MVA, Rating B MVA = 190 MVA	Length = 10 miles R = 0.008900 pu X = 0.056400 pu B = 0.007600 pu Rating A MVA = 155 MVA, Rating B MVA = 190 MVA		
Main Substation Transformer[1]	X12 = 12.708% R12 = 0.357%, X23 = 20.387% R23 = 0.58%, X13 = 5.548% R13 = 0.159%, Winding MVA = 100 MVA, Winding 1 & 2 Rating MVA = 112 MVA, Winding 3 Rating MVA = 50 MVA	X = 8.007% R = 0.233%, Winding MVA = 67.2 MVA, Rating MVA = 112 MVA		
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 43: X = 6.0% R = 0.84%, Winding MVA = 111.8 MVA, Rating MVA = 111.8 MVA	Gen 1 Equivalent Qty: 12: X = 5.947%, R = 0.793%, Winding MVA = 31.2 MVA, Rating MVA = 31.2 MVA	Gen 2 Equivalent Qty: 28: X = 5.947%, R = 0.793%, Winding MVA = 90.776 MVA, Rating MVA[2] = 90.8 MVA	Gen 3 Equivalent Qty: 3: X = 5.947%, R = 0.793%, Winding MVA = 7.8 MVA, Rating MVA = 7.8 MVA
Equivalent Collector Line[3]	R = 0.007460 pu X = 0.006920 pu B = 0.038000 pu	R = 0.007405 pu X = 0.008044 pu B = 0.036354 pu		
Reactive Power Devices	3 x 5 MVAR 34.5 kV Capacitor Bank	2 x 15 MVAR 115 kV Capacitor Bank		

1) X/R based on Winding MVA, 2) Rating rounded in PSS/E, 3) all pu are on 100 MVA Base

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 Group 3 study models.

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

3.1 POI Injection Comparison

The real power injection at the POI was determined using PSS/E to compare the DISIS-2017-001 power flow configuration and the requested modifications with the PPC in place for GEN-2008-079. 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 2.60%) 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-2008-079 POI Injection Comparison

Interconnection Request	Existing POI Injection (MW)	MRIS POI Injection (MW)	POI Injection Difference %
GEN-2008-079	96.3	98.8	2.60%

3.2 Turbine Parameters Comparison

SPP determined that short circuit and dynamic stability analyses were required because of the turbine change from Siemens to a combination of Siemens and GE turbines, the project capacity increase, and the use of a PPC. 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-2008-079 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-2008-079 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).

4.2 Results

The results from the analysis showed that the GEN-2008-079 project needed approximately 4.4 MVAr of compensation at its project substation, to reduce the POI MVAr to zero. This is a decrease from the 4.6 MVAr found for the existing GEN-2008-079 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-2008-079 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-2008-079	539783	Crooked Creek 115 kV	4.4	4.4	4.4	4.4

Figure 4-1: GEN-2008-079 Single Line Diagram (Existing Shunt Reactor)

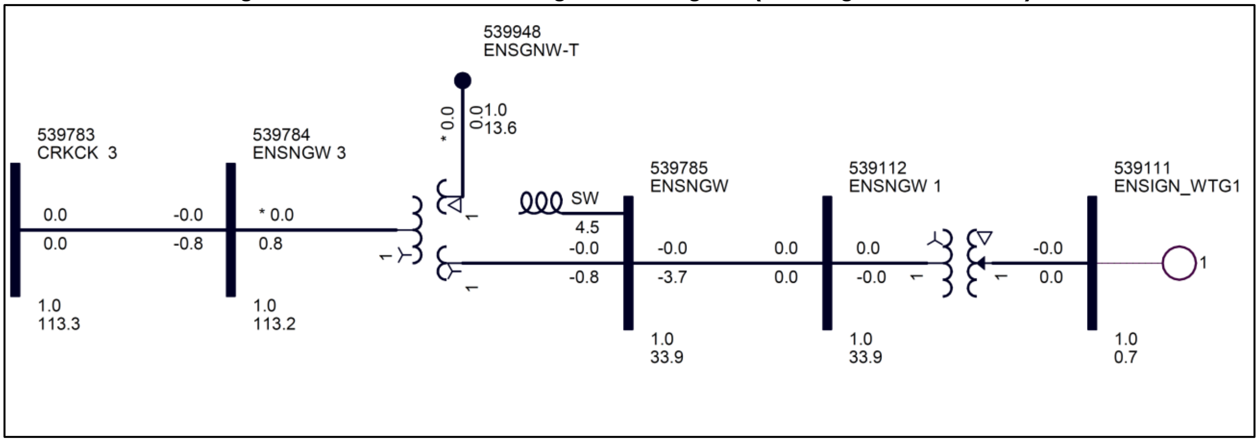
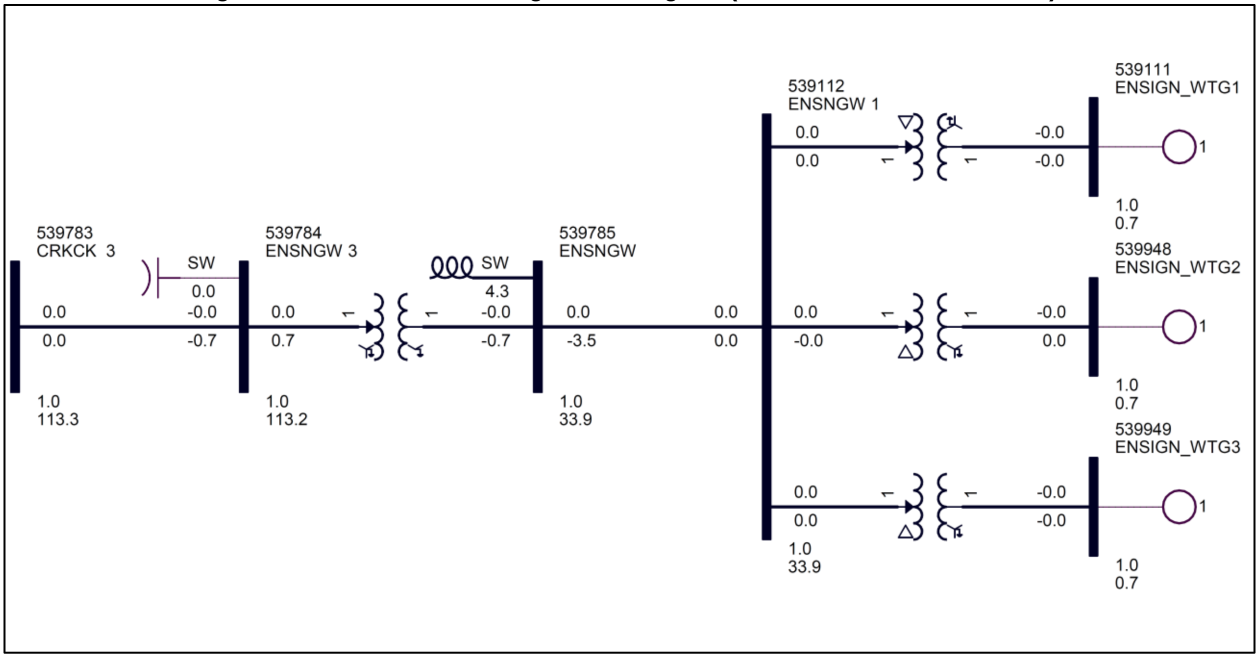


Figure 4-2: GEN-2008-079 Single Line Diagram (Modification Shunt Reactor)



5.0 Short Circuit Analysis

A short circuit study was performed using the 2021SP and 2028SP models for GEN-2008-079. 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 115 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-2008-079 online.

5.2 Results

The results of the short circuit analysis for the 2021SP and 2028SP models are summarized in Table 5-1 through Table 5-3 respectively. The GEN-2008-079 POI bus fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 5.13 kA with the GEN-2008-079 project online.

The maximum fault current calculated within 5 buses of the GEN-2008-079 POI was less than 14 kA for the 2021SP and 2028SP models respectively. The maximum GEN-2008-079 contribution to three-phase fault current was about 21.8% and 0.90 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2021SP	4.23	5.13	0.89	21.1%
2028SP	4.12	5.02	0.90	21.8%

Table 5-2: 2021SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
115	12.6	0.89	21.1%
230	12.2	0.01	0.1%
345	13.2	0.01	0.1%
Max	**13.2**	**0.89**	**21.1%**

Table 5-3: 2028SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
115	12.5	0.90	21.8%
230	12.2	0.02	0.1%
345	13.3	0.02	0.1%
Max	**13.3**	**0.90**	**21.8%**

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-2008-079 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-2008-079 configuration of 12 x Siemens 2.3 MW (SWTGU2) + 28 x Siemens 2.66 MW (SWTGU2) + 3 x GE 2.3 MW (REGCAU1). This stability analysis was performed using PTI's PSS/E version 33.10 software.

The stability models were developed using the DISIS-2017-001 Group 3 models. The modifications requested for the GEN-2008-079 projects were used to create modified stability models for this impact study.

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

1. The stability models for the Grey County generator at bus 539123 were updated with the 2020 MDGW information.

The modified dynamics model data for the GEN-2008-079 project is provided in Appendix A. The modified power flow models and associated dynamics database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2008-079 and other equally and prior queued projects in Group 3. In addition, voltages of five (5) buses away from the POI of GEN-2008-079 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 534 (SUNC), 520 (AEPW), 524 (OKGE), 526 (SPS), 531 (MIDW), 534 (SUNC), 536 (WERE), 640 (NPPD), 645 (OPPD), 650 (LES), 652 (WAPA) 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-2008-079 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
FLT51-3PH	P1	3 phase fault on the S DODGE3 (539688) to NFTDODG3 (539771) 115 kV line circuit 1, near S DODGE3. a. Apply fault at the S DODGE3 115 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.
FLT9001-3PH	P1	3 phase fault on the CRKCK 3 (539783) to FTDODGE3 (539671) 115 kV line circuit 1, near CRKCK 3. a. Apply fault at the CRKCK 3 115 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.
FLT9002-3PH	P1	3 phase fault on the CRKCK 3 (539783) to CUDAHY 3 (539659) 115 kV line circuit 1, near CRKCK 3. a. Apply fault at the CRKCK 3 115 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.
FLT9003-3PH	P1	3 phase fault on the CUDAHY 3 (539659) to KISMET 3 (539646) 115 kV line circuit 1, near CUDAHY 3. a. Apply fault at the CUDAHY 3 115 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.
FLT9004-3PH	P1	3 phase fault on the CUDAHY 3 115 kV (539659) /34.5 kV (539706) /13.8 kV (539906) transformer CKT 1, near CUDAHY 3 115 kV. a. Apply fault at the CUDAHY 3 115 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer. **Trip generator CUDAHY 1 (539706).**
FLT9005-3PH	P1	3 phase fault on the KISMET 3 (539646) to CMRIVTP3 (539652) 115 kV line circuit 1, near KISMET 3. a. Apply fault at the KISMET 3 115 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.
FLT9006-3PH	P1	3 phase fault on the FTDODGE3 (539671) to NFTDODG3 (539771) 115 kV line circuit 1, near FTDODGE3. a. Apply fault at the FTDODGE3 115 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.
FLT9007-3PH	P1	3 phase fault on the FTDODGE3 115 kV (539671) /34.5 kV (539715) /2.4 kV (539915) transformer CKT 1, near FTDODGE3 115 kV. a. Apply fault at the FTDODGE3 115 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer. **Trip generator FTDODGP1 (539715).**
FLT9008-3PH	P1	3 phase fault on the FORTDGE3 115 kV (539671) /15 kV (539670) transformer CKT 1, near FTDODGE3 115 kV. a. Apply fault at the FTDODGE3 115 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer. **Trip generator FTDDGDV1 (539670).**
FLT9009-3PH	P1	3 phase fault on the FTDODGE3 (539671) to DCBEEF3 (539645) 115 kV line circuit 1, near FTDODGE3. a. Apply fault at the FTDODGE3 115 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.
FLT9010-3PH	P1	3 phase fault on the NFTDODG3 (539771) to SPEARVL3 (539694) 115 kV line circuit 1, near NFTDODG3. a. Apply fault at the NFTDODG3 115 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.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9011-3PH	P1	3 phase fault on the NFTDODG3 (539771) to SPRVL 3 (539759) 115 kV line circuit 1, near NFTDODG3. a. Apply fault at the NFTDODG3 115 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.
FLT9012-3PH	P1	3 phase fault on the NFTDODG3 (539771) to S DODGE3 (539688) 115 kV line circuit 1, near NFTDODG3. a. Apply fault at the NFTDODG3 115 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.
FLT9013-3PH	P1	3 phase fault on the NFTDODG3 (539771) to FORD 3 (539758) 115 kV line circuit 1, near NFTDODG3. a. Apply fault at the NFTDODG3 115 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.
FLT9014-3PH	P1	3 phase fault on the DCBEEF3 (539645) to EDODGE 3 (539740) 115 kV line circuit 1, near DCBEEF3. a. Apply fault at the DCBEEF3 115 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.
FLT9015-3PH	P1	3 phase fault on the SPEARVILLE 115 kV (539759) /345 kV (531469) /13.8 kV (539960) transformer CKT 1, near SPRVL 3 115 kV. a. Apply fault at the SPRVL 3 115 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9016-3PH	P1	3 phase fault on the SPEARVL6 115 kV (539694) /230 kV (539695) /13.8 kV (539935) transformer CKT 1, near SPEARVL3 115 kV. a. Apply fault at the SPEARVL3 115 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9017-PO1	P6	**PRIOR OUTAGE of CRKCK 3 (539783) to FTDODGE3 (539671) 115 kV line circuit 1;** 3 phase fault on the CMRIVTP3 (539652) to E-LIBER3 (539672) 115 kV line circuit 1, near CMRIVTP3. a. Apply fault at the CMRIVTP3 115 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.
FLT9004-PO1	P6	**PRIOR OUTAGE of CRKCK 3 (539783) to FTDODGE3 (539671) 115 kV line circuit 1;** 3 phase fault on the CUDAHY 3 115 kV (539659) /34.5 kV (539706) /13.8 kV (539906) transformer CKT 1, near CUDAHY 3 115 kV. a. Apply fault at the CUDAHY 3 115 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer. **Trip generator CUDAHY 1 (539706).**
FLT9018-PO1	P6	**PRIOR OUTAGE of CRKCK 3 (539783) to FTDODGE3 (539671) 115 kV line circuit 1;** 3 phase fault on the CMRIVTP3 (539652) to CIM-PLT3 (539654) 115 kV line circuit 1, near CMRIVTP3. a. Apply fault at the CMRIVTP3 115 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.
FLT9006-PO2	P6	**PRIOR OUTAGE of CRKCK 3 (539783) to CUDAHY 3 (539659) 115 kV line circuit 1;** 3 phase fault on the FTDODGE3 (539671) to NFTDODG3 (539771) 115 kV line circuit 1, near FTDODGE3. a. Apply fault at the FTDODGE3 115 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.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9007-PO2	P6	**PRIOR OUTAGE of CRKCK 3 (539783) to CUDAHY 3 (539659) 115 kV line circuit 1;** 3 phase fault on the FTDODGE3 115 kV (539671) /34.5 kV (539715) /13.8 kV (539915) transformer CKT 1, near FTDODGE3 115 kV. a. Apply fault at the FTDODGE3 115 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer. **Trip generator FTDDGDV1 (539715).**
FLT9008-PO2	P6	**PRIOR OUTAGE of CRKCK 3 (539783) to CUDAHY 3 (539659) 115 kV line circuit 1;** 3 phase fault on the FORTDGE3 115 kV (539671) /15 kV (539670) transformer CKT 1, near FTDODGE3 115 kV. a. Apply fault at the FTDODGE3 115 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer. **Trip generator FTDODGP1 (539670).**
FLT9009-PO2	P6	**PRIOR OUTAGE of CRKCK 3 (539783) to CUDAHY 3 (539659) 115 kV line circuit 1;** 3 phase fault on the FTDODGE3 (539671) to DCBEEF3 (539645) 115 kV line circuit 1, near FTDODGE3. a. Apply fault at the FTDODGE3 115 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.
FLT9016-PO3	P6	**PRIOR OUTAGE of SPEARVILLE 115 kV (539759) /345 kV (531469) /13.8 kV (539960) transformer CKT 1;** 3 phase fault on the SPEARVL6 115 kV (539694) /230 kV (539695) /13.8 kV (539935) transformer CKT 1, near SPEARVL3 115 kV. a. Apply fault at the SPEARVL3 115 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT1001-SB	P4	**Stuck Breaker on at CRKCK 3 (539783) at 115kV bus** a. Apply single-phase fault at CRKCK 3 (539783) on the 115kV bus. b. After 16 cycles, trip the following elements c. Trip the Bus CRKCK 3 (539783). Trip GEN-2008-079
FLT1002-SB	P4	**Stuck Breaker on at CUDAHY 3 (539659) at 115kV bus** a. Apply single-phase fault at CUDAHY 3 (539659) on the 115kV bus. b. After 16 cycles, trip the following elements c. Trip the Bus CUDAHY 3 (539659).
FLT1003-SB	P4	**Stuck Breaker on at FTDODGE3 (539671) at 115kV bus** a. Apply single-phase fault at FTDODGE3 (539671) on the 115kV bus. b. After 16 cycles, trip the following elements c. Trip the FTDODGE3 (539671) to DCBEEF3 (539645) 115 kV line circuit 1. d. Trip the FTDODGE3 (539671) to NFTDODG3 (539771) 115 kV line circuit 1.
FLT1004-SB	P4	**Stuck Breaker on at FTDODGE3 (539671) at 115kV bus** a. Apply single-phase fault at FTDODGE3 (539671) on the 115kV bus. b. After 16 cycles, trip the following elements c. Trip the FTDODGE3 (539671) to DCBEEF3 (539645) 115 kV line circuit 1. d. Trip the FTDODGE3 115 kV (539671) /34.5 kV (539715) /2.4 kV (539915) transformer CKT 1. **Trip generator FTDDGDV1 (539715).**
FLT1005-SB	P4	**Stuck Breaker on at FTDODGE3 (539671) at 115kV bus** a. Apply single-phase fault at FTDODGE3 (539671) on the 115kV bus. b. After 16 cycles, trip the following elements c. Trip the FTDODGE3 (539671) to NFTDODGE3 (539771) 115 kV line circuit 2. d. Trip the FTDODGE3 115 kV (539671) /34.5 kV (539715) /2.4 kV (539915) transformer CKT 1. **Trip generator FTDDGDV1 (539715).**
FLT1006-SB	P4	**Stuck Breaker on at FTDODGE3 (539671) at 115kV bus** a. Apply single-phase fault at FTDODGE3 (539671) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the FTDODGE3 (539671) to NFTDODGE3 (539771) 115 kV line circuit 2. d. Trip the FTDODGE3 (539671) to CRKCK 3 (539783) 115 kV line circuit 1.
FLT1007-SB	P4	**Stuck Breaker on at FTDODGE3 (539671) at 115kV bus** a. Apply single-phase fault at FTDODGE3 (539671) on the 115kV bus. b. After 16 cycles, trip the following elements c. Trip the FORTDGE3 115 kV (539671) /15 kV (539670) transformer CKT 1. d. Trip the FTDODGE3 (539671) to CRKCK 3 (539783) 115 kV line circuit 1. **Trip generator FTDODGP1 (539670).**

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT1008-SB	P4	**Stuck Breaker on at FTDODGE3 (539671) at 115kV bus** a. Apply single-phase fault at FTDODGE3 (539671) on the 115kV bus. b. After 16 cycles, trip the following elements c. Trip the FORTDGE3 115 kV (539671) /15 kV (539670) transformer CKT 1. d. Trip the FTDODGE3 (539671) to NFTDODG3 (539771) 115 kV line circuit 1. **Trip generator FTDODGP1 (539670).**
FLT9017-3PH	P1	3 phase fault on the CMRIVTP3 (539652) to E-LIBER3 (539672) 115 kV line circuit 1, near CMRIVTP3. a. Apply fault at the CMRIVTP3 115 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.
FLT9018-3PH	P1	3 phase fault on the CMRIVTP3 (539652) to CIM-PLT3 (539654) 115 kV line circuit 1, near CMRIVTP3. a. Apply fault at the CMRIVTP3 115 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.

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-2008-079 Dynamic Stability Results

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT51-3PH	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
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9004-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

There were no damping or voltage recovery violations attributed to the GEN-2008-079 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-2008-079 (108.98 MW) exceeds the GIA Interconnection Service amount, 98.9 MW, as listed in Appendix A.

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 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-2008-079 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-2008-079 requested a Modification Request Impact Study to assess the impact of the turbine and facility change to a configuration of 12 x Siemens 2.3 MW + 28 x Siemens 2.66 MW + 3 x GE 2.3 MW for a total generating capacity of 108.98 MW. The generating capacity for GEN-2008-079 (108.98 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, 98.9 MW, as listed in Appendix A. The customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformer, and reactive power devices.

SPP determined that power flow should not be performed based on the POI MW injection increase of 2.60% compared to the recently studied DISIS-2017-001 power flow models. However, SPP determined that the turbine change from Siemens to a combination of Siemens and GE turbines, the project capacity increase, and the use of a PPC required short circuit and dynamic stability analyses.

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-2008-079 project needed 4.4 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 4.6 MVAr found for the existing GEN-2008-079 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-2008-079 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2008-079 POI was not greater than 0.90 kA for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2008-079 generators online were below 14 kA for the 2021SP and 2028SP models.

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 35 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 dynamic stability analysis showed that there were no damping or voltage recovery violations attributed to the GEN-2008-079 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.