Report on

GEN-2023-SR23
Surplus Service Impact Study

Revision R1 October 25, 2023

Submitted to
Southwest Power Pool

SPP Southwest Power Pool

anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
10/25/2023	Aneden Consulting	Initial Report Issued

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Surplus Interconnection Service Impact Study (Study) for GEN-2023-SR23 to utilize the Surplus Interconnection Service being made available by the GEN-2016-167 at its existing Point of Interconnection (POI), on the Lieberman to North Benton 138 kV line in the American Electric Power (AEP) control area.

GEN-2023-SR23, the proposed Surplus Generating Facility (SGF), will connect to the existing GEN-2016-167 main collection substation and share its main power transformer.

GEN-2016-167 the Existing Generating Facility (EGF), has an effective Generator Interconnection Agreement (GIA) with a POI capacity of 73.5 MW and is making 73.5 MW of Surplus Interconnection Service available at its POI. Per the SPP Open Access Transmission Tariff (SPP Tariff), the amount of Surplus Interconnection Service available to the SGF is limited by the amount of Interconnection Service granted to the EGF at the same POI. In addition, the Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring Network Upgrades except those specified in the SPP Tariff[1].

The proposed SGF configuration consists of 20 x PE FP4200M2 Battery Energy Storage System (BESS) inverters operating at 3.694 MW for a total assumed dispatch of 73.88 MW. The inverters are rated at 4.2 MW, thus the generating capability of the SGF (84 MW) exceeds its requested Surplus Interconnection Service of 73.5 MW. The injection amount of the SGF must be limited to 73.5 MW at the POI. The combined generation from both the SGF and the EGF may not exceed 73.5 MW at the POI. GEN-2023-SR23 includes the use of a Power Plant Controller (PPC) to limit the power injection as required. The SGF and EGF information is shown in Table ES-1 below.

The detailed SGF configuration is captured in Table ES-2 below.

Table ES-1: EGF & SGF Configuration

Request	Interconnection Queue Capacity (MW)	Fuel Type	Point of Interconnection
GEN-2023-SR23 (SGF)	73.5	Battery/Storage	Tap on Lieberman (508806) to North Benton (508811) 138 kV line (G16-167-TAP 588404)
GEN-2016-167 (EGF)	73.5	Solar	Tap on Lieberman (508806) to North Benton (508811) 138 kV line (G16-167-TAP 588404)

[1] Allowed Network Upgrades detailed in SPP Open Access Transmission Tariff Attachment V Section 3.3

Table ES-2: SGF Interconnection Configuration

Facility	SGF Configuration
Point of Interconnection	Tap on Lieberman (508806) to North Benton (508811) 138 kV line (G16-167-TAP 588404)
Configuration/Capacity	20 x PE FP4200M2 3.694 MW (BESS) = 73.88 MW [dispatch] Units are rated at 4.2 MW, PPC to limit GEN-2023-SR23 to 73.5 MW at the POI and total POI injection w/ GEN-2016-167 to 73.5 MW
Generation Interconnection Line (Shared with the EGF per the DISIS-2017-002-1 models and unchanged)	Length = 4 miles R = 0.000200 pu X = 0.000400 pu B = 0.000100 pu Rating MVA = 0 MVA
Main Substation Transformer[1] (Shared with the EGF per the DISIS-2017-002-1 models and unchanged)	X = 8.997%, R = 0.225%, Winding MVA = 60 MVA, Rating MVA = 100 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 20 X = 8.462%, R = 0.806%, Winding MVA = 84.14 MVA, Rating MVA[2] = 84.1 MVA
Equivalent Collector Line[3]	R = 0.000218 pu X = 0.000286 pu B = 0.000469 pu
Generator Dynamic Model[4] & Power Factor	20 x PE FP4200M2 4.2 MVA (REGCAU1)[4] Leading: 0.879 Lagging: 0.879

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

SPP determined that steady-state analysis was not required because the addition of the SGF does not increase the maximum active power output of 73.5 MW. In addition, the EGF was previously studied at maximum Interconnection Service under all necessary reliability conditions.

The scope of this study included reactive power analysis, short circuit analysis, and dynamic stability analysis.

Aneden performed the analyses using the study data provided for the SGF and the DISIS-2017-002-1 study models:

- 2025 Summer Peak (25SP),
- 2025 Winter Peak (25WP)

All analyses were performed using the Siemens PTI PSS/E[2] version 34 software and the results are summarized below.

The results of the reactive power analysis using the 25SP model showed that the SGF project did not need a shunt reactor at the project substation to reduce the POI MVAr to zero when the EGF project had a shunt compensating for its charging effects. No additional compensation was necessary to offset the capacitive effect on the transmission network caused by the project during reduced generation conditions. The information gathered from the reactive power analysis is provided as information to the Interconnection

[2] Power System Simulator for Engineering

Customer and Transmission Owner (TO) and/or Transmission Operator (TOP). The applicable reactive power requirements will be further reviewed by the TO and/or TOP.

The short circuit analysis was performed using the 25SP stability model modified for short circuit analysis. The results from the short circuit analysis compared the 25SP model with the EGF online and SGF not connected to the SGF study model (EGF and SGF online). The maximum contribution to three-phase fault currents in the immediate transmission systems due to the addition of the SGF was not greater than 0.31 kA. The maximum three-phase fault current level within 5 buses of the POI with the EGF and SGF generators online was below 42 kA for the 25SP model. There was a bus with a maximum three-phase fault current over 40 kA. This bus is highlighted in Appendix B.

The dynamic stability analysis was performed using Siemens PTI PSS/E version 34.8.0 software for the two modified study models: 25SP and 25WP, each with two dispatch scenarios. 39 events were simulated, which included three-phase faults and single-line-to-ground stuck breaker faults.

- Scenario 1: SGF at maximum assumed dispatch, 73.88 MW (limited to 73.5 MW at the POI), and EGF disconnected.
- Scenario 2: Aneden and SPP selected the second scenario based on a combination of SGF and EGF dispatch scenarios with the project dispatches varied by 10 MW increments of the total EGF capacity of 73.5 MW. The resulting selected worst-case scenario included a combination of the SGF dispatched to 10 MW and the EGF to 63.5 MW for a total combination of 73.5 MW.

The results of the dynamic stability analysis showed several existing base case issues that were found in both the original DISIS-2017-002-1 model and in the model with GEN-2023-SR23 included. These issues were not attributed to the GEN-2023-SR23 surplus request and are detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2023-SR23 surplus request 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 results of the study showed that the Surplus Interconnection Service Request by GEN-2023-SR23 did not negatively impact the reliability of the Transmission System. There were no additional Interconnection Facilities or Network Upgrades identified by the analyses.

SPP has determined that GEN-2023-SR23 may utilize the requested 73.5 MW of Surplus Interconnection Service being made available by the EGF. The combined generation from both the SGF and the EGF may not exceed 73.5 MW at the POI.

The customer must install monitoring and control equipment as needed to ensure that the SGF does not exceed the granted surplus amount and to ensure that combination of the SGF and EGF power injected at the POI does not exceed the Interconnection Service amount listed in the EGF's GIA. The monitoring and control scheme may be reviewed by the TO and documented in Appendix C of the SGF GIA.

In accordance with FERC Order No. 827, both the SGF and EGF 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 Surplus Service Impact Study (Study) for GEN-2023-SR23, the Surplus Generating Facility (SGF). A Surplus Service Impact Study is performed to identify the impact of the Surplus Interconnection Service on the transmission system reliability and any additional Interconnection Facilities necessary pursuant to the SPP Generator Interconnection Procedures (“GIP”) contained in Attachment V Section 3.3 of the SPP Open Access Transmission Tariff (SPP Tariff). The amount of Surplus Interconnection Service available to the SGF is limited by the amount of Interconnection Service granted to the existing interconnection customer for the Existing Generating Facility (EGF) at the same POI. The Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades except those specified in the SPP Tariff[3]. The required scope of the study is dependent upon the EGF and SGF specifications. The criteria sections below include the basis of the analyses included in the scope of study.

All analyses were performed using the Siemens PTI PSS/E version 34 software. The results of each analysis are presented in the following sections.

1.1 Reactive Power Analysis

SPP requires that a reactive power analysis be performed on the requested configuration if it is a non-synchronous resource. The reactive power analysis determines the added capacitive effect at the POI caused by the project’s collection system and transmission line’s capacitance. A shunt reactor size was determined for the SGF to offset the capacitive effect and maintain zero (0) MVAr injection at the POI while the plant’s generators and capacitors were offline, and the EGF project had a shunt compensating for its charging effects.

1.2 Short Circuit Analysis

SPP requires that a short circuit analysis be performed to determine the maximum available fault current requiring interruption by protective equipment with both the SGF and EGF online, along with the amount of increase in maximum fault current due to the addition of the SGF. The analysis was performed on two scenarios, with the EGF in service and SGF offline, and the modified model with both EGF and SGF in service.

1.3 Stability Analysis

SPP requires that a dynamic stability analysis be performed to determine whether the SGF, EGF, and the transmission system will remain stable and within applicable criteria. Dynamic stability analysis was performed on two dispatch scenarios, the first where the SGF was online at 100% of the assumed dispatch with the EGF offline and disconnected, and the second which is determined to be the worst-case scenario based on a dispatch test described in Section 5.1. The stability analyses will identify any additional Interconnection Facilities and Network Upgrades necessary.

1.4 Steady-State Analysis

The steady-state (thermal/voltage) analyses may be performed as necessary to ensure that all required reliability conditions are studied. If the EGF was not studied under off-peak conditions, off-peak steady state analyses shall be performed to the required level necessary to demonstrate reliable operation of the Surplus Interconnection Service. If the original system impact study is not available for the

[3] Allowed Network Upgrades detailed in SPP Open Access Transmission Tariff Attachment V Section 3.3

Interconnection Service, both off-peak and peak analysis may need to be performed for the EGF associated with the request.

An SGF that includes a fuel type (synchronous/non-synchronous) different from the EGF may require a steady-state analysis to study impacts resultant from changes in dispatch to all equal and lower queued requests. The steady-state analyses will identify any additional Interconnection Facilities and Network Upgrades necessary.

1.5 Necessary Interconnection Facilities & Network Upgrades

The SPP Tariff[4] states that the reactive power, short circuit/fault duty, stability, and steady-state analyses (where applicable) for the Surplus Interconnection Service will identify any additional Interconnection Facilities necessary. In addition, the analyses will determine if any Network Upgrades are required for mitigation. The Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades unless (a) those additional Network Upgrades are either (1) located at the Point of Interconnection substation and at the same voltage level as the Generating Facility with an effective GIA, or (2) are System Protection Facilities; and (b) there are no material adverse impacts on the cost or timing of any Interconnection Requests pending at the time the Surplus Interconnection Service request is submitted.

1.6 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.

[4] SPP Open Access Transmission Tariff Section 3.3.4.1

2.0 Surplus Interconnection Service Request

The GEN-2023-SR23 Interconnection Customer has requested a Surplus Interconnection Service Impact Study (Study) for GEN-2023-SR23 to utilize the Surplus Interconnection Service being made available by GEN-2016-167 at its existing Point of Interconnection (POI), on the Lieberman to North Benton 138 kV line in the American Electric Power (AEP) control area.

GEN-2023-SR23, the proposed SGF, will connect to the existing GEN-2016-167 main collection substation and share its main power transformer.

GEN-2016-167, the EGF, has an effective Generation Interconnection Agreement (GIA) with a POI capacity of 73.5 MW and is making 73.5 MW of Surplus Interconnection Service available at its POI. Per the SPP Tariff the amount of Surplus Interconnection Service available to the SGF is limited by the amount of Interconnection Service granted to the EGF at the same POI. In addition, the Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades except those specified in the SPP Tariff.

At the time of the posting of this report, GEN-2016-167 (EGF) is an active existing generator at the same POI (Lieberman – North Benton 138 kV Line) with a queue status of “IA FULLY EXECUTED/ON SCHEDULE”. GEN-2016-167 is a solar farm, has a maximum summer and winter queue capacity of 73.5 MW, and has Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). The EGF was originally studied in the DISIS-2016-002 cluster study. Figure 2-1 shows the power flow model single line diagram for the EGF configuration.

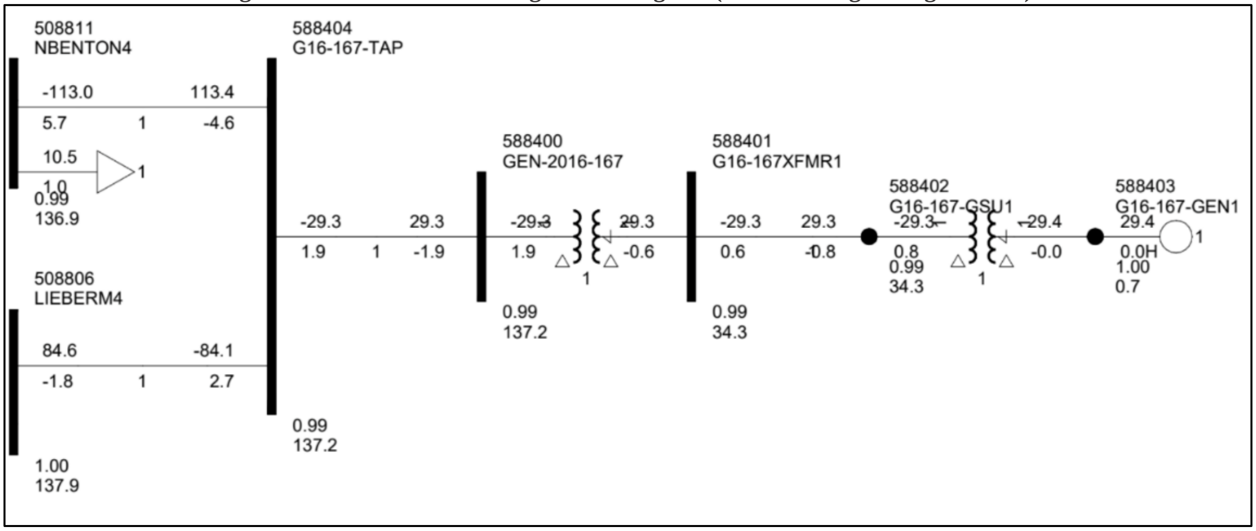
The proposed SGF configuration consists of 20 x PE FP4200M2 Battery Energy Storage System (BESS) inverters operating at 3.694 MW for a total assumed dispatch of 73.88 MW. The inverters are rated at 4.2 MW, thus the generating capability of the SGF (84 MW) exceeds its requested Surplus Interconnection Service of 73.5 MW. The injection amount of the SGF must be limited to 73.5 MW at the POI. The combined generation from both the SGF and the EGF may not exceed 73.5 MW at the POI. GEN-2023-SR23 includes the use of a Power Plant Controller (PPC) to limit the power injection as required. The SGF and EGF information is shown in Table 2-1 below.

Table 2-1: EGF & SGF Configuration

Request	Interconnection Queue Capacity (MW)	Fuel Type	Point of Interconnection
GEN-2023-SR23 (SGF)	73.5	Battery/Storage	Tap on Lieberman (508806) to North Benton (508811) 138 kV line (G16-167-TAP 588404)
GEN-2016-167 (EGF)	73.5	Solar	Tap on Lieberman (508806) to North Benton (508811) 138 kV line (G16-167-TAP 588404)

The proposed detailed SGF configuration is captured in Figure 2-2 and Table 2-2 below.

Figure 2-1: GEN-2016-167 Single Line Diagram (EGF Existing Configuration*)



*based on the DISIS-2017-002-1 25SP stability models

Figure 2-2: GEN-2016-167 & GEN-2023-SR23 Single Line Diagram (EGF & SGF Configuration)

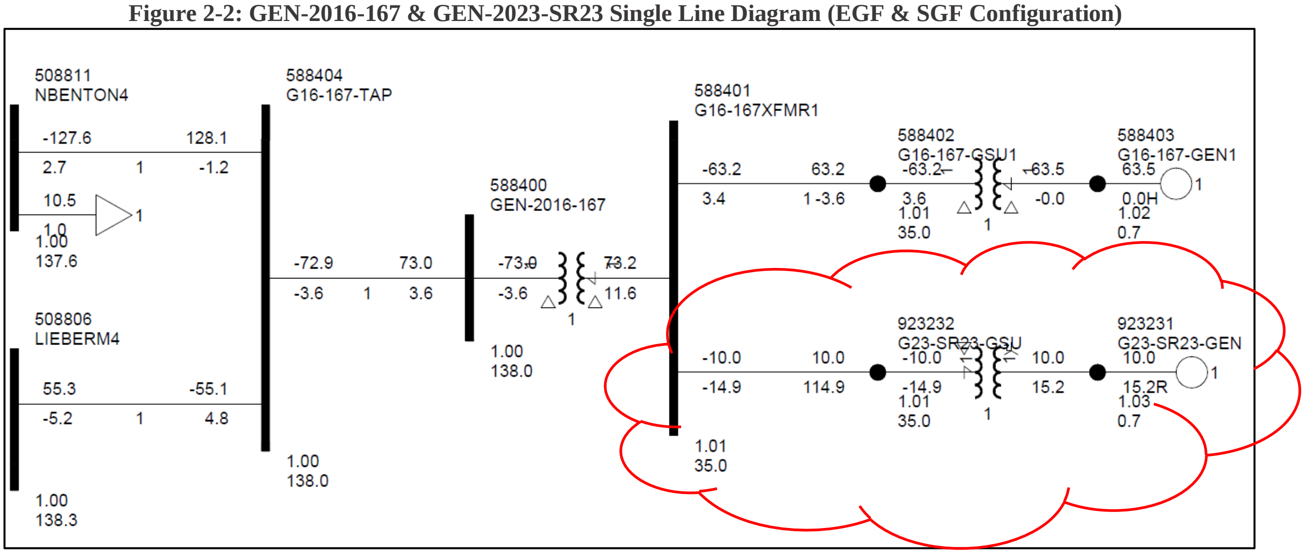


Table 2-2: SGF Interconnection Configuration

Facility	SGF Configuration
Point of Interconnection	Tap on Lieberman (508806) to North Benton (508811) 138 kV line (G16-167-TAP 588404)
Configuration/Capacity	20 x PE FP4200M2 3.694 MW (BESS) = 73.88 MW [dispatch] Units are rated at 4.2 MW, PPC to limit GEN-2023-SR23 to 73.5 MW at the POI and total POI injection w/ GEN-2016-167 to 73.5 MW
Generation Interconnection Line (Shared with the EGF per the DISIS-2017-002-1 models and unchanged)	Length = 4 miles R = 0.000200 pu X = 0.000400 pu B = 0.000100 pu Rating MVA = 0 MVA
Main Substation Transformer[1] (Shared with the EGF per the DISIS-2017-002-1 models and unchanged)	X = 8.997%, R = 0.225%, Winding MVA = 60 MVA, Rating MVA = 100 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 20 X = 8.462%, R = 0.806%, Winding MVA = 84.14 MVA, Rating MVA[2] = 84.1 MVA
Equivalent Collector Line[3]	R = 0.000218 pu X = 0.000286 pu B = 0.000469 pu
Generator Dynamic Model[4] & Power Factor	20 x PE FP4200M2 4.2 MVA (REGCAU1)[4] Leading: 0.879 Lagging: 0.879

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

3.0 Reactive Power Analysis

The reactive power analysis was performed for GEN-2023-SR23 to determine the capacitive charging effects due to the SGF 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.

3.1 Methodology and Criteria

In order to determine the shunt reactor size required to compensate for the current charging attributed to the SGF collection system, the reactive power analysis for the EGF was determined first. Once the shunt size for the EGF was determined, the SGF incremental shunt reactor size was then calculated.

For each of the shunt reactor sizes calculated, all project generators were switched offline while other collector system elements remained in-service. For the SGF reactor size calculation, the EGF generators were also switched offline. 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 reactive power analysis using the SGF data based on the 25SP DISIS-2017-002-1 stability study model.

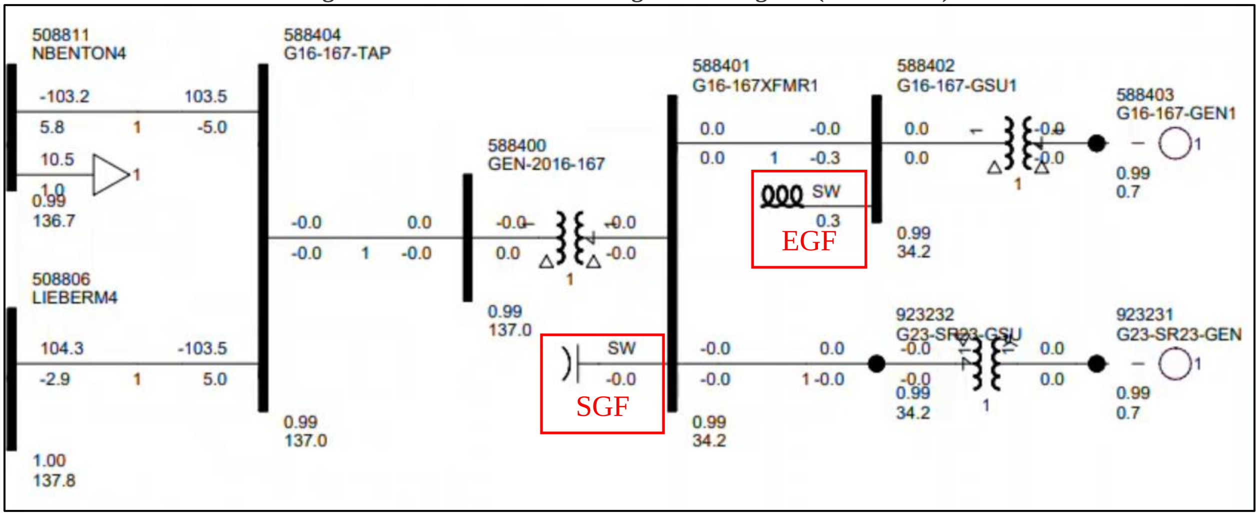
3.2 Results

Per the methodology described above, the shunt size was determined for the EGF prior to calculating the shunt reactor size for the SGF. The shunt size was found to be a 0.3 MVAr reactor for the EGF to reduce the POI MVAr to approximately zero. Note that the EGF shunt value is for the SGF reactive size determination only and not for sizing the predetermined EGF reactive requirements.

The results from the analysis showed that the SGF did not need a shunt reactor at the project substation to reduce the POI MVAr to zero with the pre-determined shunt for the EGF in-service. Figure 3-1 illustrates that no additional compensation was necessary to offset the capacitive effect on the transmission network caused by the project during reduced generation conditions.

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

Figure 3-1: GEN-2023-SR23 Single Line Diagram (Shunt Sizes)



4.0 Short Circuit Analysis

A short circuit study was performed using the 25SP model to determine the maximum available fault current requiring interruption by protective equipment with both the SGF and EGF online for each bus in the relevant subsystem, and the amount of increase in maximum fault current due to the addition of the SGF. The detailed results of the short circuit analysis are provided in Appendix B.

4.1 Methodology

The short circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 138 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels in the transmission system with and without the SGF online. The first scenario was studied with both the SGF and EGF in service. In the second scenario the SGF was disconnected while the EGF was online to determine the impact of the SGF.

Aneden created a short circuit model using the 25SP DISIS-2017-002-1 stability study model by adjusting the SGF short circuit parameters consistent with the submitted data. The adjusted parameters used in the short circuit analysis are shown in Table 4-1 below. No other changes were made to the model.

Table 4-1: Short Circuit Model Parameters*

Parameter	Value by Generator Bus#
	923231
Machine MVA Base	84
R (pu)	0.0
X'' (pu)	0.893

*pu values based on Machine MVA Base

4.2 Results

The results of the short circuit analysis compared the 25SP model with the EGF online and SGF not connected to the stability Scenario 2 dispatch model with both the EGF and SGF in service as described in Section 5.1. The GEN-2023-SR23 POI bus (G16-167-TAP 138 kV - 588404) fault current magnitudes for the comparison cases are provided in Table 4-2 showing a fault current of 10.04 kA with the EGF and SGF online. The addition of the SGF configuration increased the POI bus fault current by 0.31 kA. Table 4-3 shows the maximum fault current magnitudes and fault current increases with the SGF project online.

The maximum fault current calculated within 5 buses of the POI was less than 42 kA for the 25SP model. There was a bus with a maximum three-phase fault current over 40 kA. This bus is highlighted in Appendix B. The maximum contribution to three-phase fault currents due to the addition of the SGF was about 3.2% and 0.31 kA.

Table 4-2: POI Short Circuit Comparison Results

Case	EGF Only Current (kA)	SGF & EGF Current (kA)	kA Change	%Change
25SP	9.72	10.04	0.31	3.2%

Table 4-3: 25SP Short Circuit Comparison Results

Voltage (kV)	Max. Current (EGF & SGF) (kA)	Max kA Change	Max %Change
69	28.1	0.09	0.3%
115	19.5	0.01	0.0%
138	41.6	0.31	3.2%
345	20.9	0.04	0.3%
Max	**41.6**	**0.31**	**3.2%**

5.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the SGF project. The analysis was performed according to SPP's Disturbance Performance Requirements[5]. The project details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix A. The existing base case issues and simulation plots can be found in Appendix C.

5.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested 20 x PE FP4200M2 inverters operating at 3.694 MW (REGCAU1) SGF generating facility configuration included in the models. This stability analysis was performed using Siemens PTI's PSS/E version 34.8.0 software.

Two stability model scenarios were developed using the models from DISIS-2017-002-1. The first scenario (Scenario 1) was comprised of the SGF online at 100% of the assumed dispatch (SGF = 73.88 MW) while the EGF generator was offline and disconnected.

In order to determine the appropriate EGF/SGF dispatch combination for the second scenario (Scenario 2), dispatch models in 10 MW increments of the total EGF capacity were created and simulated with a POI fault. The dispatch scenarios tested are shown in Table 5-1. The nearby synchronous machine angle deviation and POI bus voltage deviation results were used to select the worst-case dispatch combination with both the EGF and SGF online for this impact study. The worst-case scenario selected is highlighted in green in the table.

Table 5-1: Scenario 2 Dispatch Tests

Dispatch Scenarios		
GEN-2016-167 EGF (MW)	GEN-2023-SR23 SGF (MW)	EGF + SGF (MW)
3.5	70	73.5
13.5	60	73.5
23.5	50	73.5
33.5	40	73.5
43.5	30	73.5
53.5	20	73.5
63.5	10	73.5

The study scenarios are shown in Table 5-2.

Table 5-2: Study Scenarios (Generator Dispatch MW)

Scenario	GEN-2016-167 EGF (MW)	GEN-2023-SR23 SGF (MW)	EGF + SGF (MW)
1	0 (Offline)	73.88	73.88
2	63.5	10	73.5*

*Scenario 2 was dispatched according to the EGF Capacity

[5] SPP Disturbance Performance Requirements: https://www.spp.org/documents/28859/spp%20disturbance%20performance%20requirements%20(twg%20approved).pdf

The GEN-2023-SR23 project details were used to create modified stability models for this impact study based on the DISIS-2017-002-1 stability study models:

- 2025 Summer Peak (25SP),
- 2025 Winter Peak (25WP)

The dynamic model data for the GEN-2023-SR23 project is provided in Appendix A. The power flow models and associated dynamic database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data.

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

- The fault simulation file acceleration factor was reduced as needed to resolve stability simulation crashes.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for the EGF and SGF and other current and prior queued projects in Group 4[6]. In addition, voltages of five (5) buses away from the POI of the SGF were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas 330 (AECI), 515 (SWPA), 520 (AEPW), 523 (GRDA), 524 (OKGE), 525 (WFEC), 527 (OMPA), and 534 (SUNC) were monitored. The voltages of all 100 kV and above buses within the study area were monitored as well.

5.2 Fault Definitions

Aneden developed and simulated fault events as required to study the SGF. The new set of faults was simulated using the modified study models. The fault events included three-phase faults and single-line-to-ground stuck breaker faults. Single-line-to-ground faults are approximated by applying a fault impedance to bring the faulted bus positive sequence voltage to 0.6 pu. The simulated faults are listed and described in Table 5-3 below. These contingencies were applied to the modified 25SP and 25WP models.

Table 5-3: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT9001-3PH	P1	3 phase fault on the G16-167-TAP (588404) to LIEBERM4 (508806) 138 kV line CKT 1, near G16-167-TAP. a. Apply fault at the G16-167-TAP 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.
FLT9002-3PH	P1	3 phase fault on the G16-167-TAP (588404) to NBENTON4 (508811) 138 kV line CKT 1, near G16-167-TAP. a. Apply fault at the G16-167-TAP 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.
FLT9003-3PH	P1	3 phase fault on the NBENTON4 (508811) to LINTNRD4 (508807) 138 kV line CKT 1, near NBENTON4. a. Apply fault at the NBENTON4 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.

[6] Based on the DISIS-2017-002 Cluster Groups

Table 5-3 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9004-3PH	P1	3 phase fault on the N BENTON 138 kV (508811) /69 kV (508810) /13.2 kV (508823) XFMR CKT 1, near NBENTON4 (508811) 138 kV. a. Apply fault at the NBENTON4 (508811) 138 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9005-3PH	P1	3 phase fault on the LINTNRD4 (508807) to DEENPNT4 (507772) 138 kV line CKT 1, near LINTNRD4. a. Apply fault at the LINTNRD4 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.
FLT9006-3PH	P1	3 phase fault on the DEENPNT4 (507772) to RDPOINT4 (507751) 138 kV line CKT 1, near DEENPNT4. a. Apply fault at the DEENPNT4 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.
FLT9007-3PH	P1	3 phase fault on the RDPOINT4 (507751) to BODCAU 4 (507715) 138 kV line CKT 1, near RDPOINT4. a. Apply fault at the RDPOINT4 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.
FLT9008-3PH	P1	3 phase fault on the RDPOINT4 (507751) to HAUGHTN4 (507736) 138 kV line CKT 1, near RDPOINT4. a. Apply fault at the RDPOINT4 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.
FLT9009-3PH	P1	3 phase fault on the RDPOINT1 138 kV (507751) /69 kV (507750) /13.2 kV (507780) XFMR CKT 1, near RDPOINT4 (507751) 138 kV. a. Apply fault at the RDPOINT4 (507751) 138 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9010-3PH	P1	3 phase fault on the LIEBERM4 (508806) to ARSHILL4 (507711) 138 kV line CKT 1, near LIEBERM4. a. Apply fault at the LIEBERM4 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.
FLT9011-3PH	P1	3 phase fault on the LIEBERM4 (508806) to LONGWD 4 (508808) 138 kV line CKT 1, near LIEBERM4. a. Apply fault at the LIEBERM4 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.
FLT9012-3PH	P1	3 phase fault on the LIEBERM4 (508806) to IPCJEFF4 (508833) 138 kV line CKT 1, near LIEBERM4. a. Apply fault at the LIEBERM4 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.
FLT9013-3PH	P1	3 phase fault on the LIEBRMN1 138 kV (508806) /69 kV (508805) /13.2 kV (508820) XFMR CKT 1, near LIEBERM4 (508806) 138 kV. a. Apply fault at the LIEBERM4 (508806) 138 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9014-3PH	P1	3 phase fault on the LIEB 2-1 138 kV (508806) /13.8 kV (509400) XFMR CKT 1, near LIEBERM4 (508806) 138 kV. a. Apply fault at the LIEBERM4 (508806) 138 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer. Trip generator on bus LIEBR2-1 (509400)

Table 5-3 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9015-3PH	P1	3 phase fault on the LIEB 4-1 138 kV (508806) /13.8 kV (509402) XFMR CKT 1, near LIEBERM4 (508806) 138 kV. a. Apply fault at the LIEBERM4 (508806) 138 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer. Trip generator on bus LIEBR4-1 (509402)
FLT9016-3PH	P1	3 phase fault on the LIEB 3-1 138 kV (508806) /13.8 kV (509401) XFMR CKT 1, near LIEBERM4 (508806) 138 kV. a. Apply fault at the LIEBERM4 (508806) 138 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer. Trip generator on bus LIEBR3-1 (509401)
FLT9017-3PH	P1	3 phase fault on the ARSHILL4 (507711) to STLGENS4 (507789) 138 kV line CKT 1, near ARSHILL4. a. Apply fault at the ARSHILL4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. Trip generator on bus STALL6S (509393), STALL6A (509391), STALL6B (509392) 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 ARSHILL4 (507711) to MCWILLI4 (507742) 138 kV line CKT 1, near ARSHILL4. a. Apply fault at the ARSHILL4 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.
FLT9019-3PH	P1	3 phase fault on the ARSHILL4 (507711) to FTHUMBG4 (507731) 138 kV line CKT 1, near ARSHILL4. a. Apply fault at the ARSHILL4 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.
FLT9020-3PH	P1	3 phase fault on the ARSHILL4 (507711) to RAINES 4 (507749) 138 kV line CKT 1, near ARSHILL4. a. Apply fault at the ARSHILL4 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.
FLT9021-3PH	P1	3 phase fault on the ARSHILL1 138 kV (507711) /69 kV (507710) /12.47 kV (507712) XFMR CKT 1, near ARSHILL4 (507711) 138 kV. a. Apply fault at the ARSHILL4 (507711) 138 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9022-3PH	P1	3 phase fault on the LONGWD 4 (508808) to NORAM 4 (507774) 138 kV line CKT 1, near LONGWD 4. a. Apply fault at the LONGWD 4 138 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.
FLT9023-3PH	P1	3 phase fault on the LONGWD 4 (508808) to OAKPH 4 (508816) 138 kV line CKT 1, near LONGWD 4. a. Apply fault at the LONGWD 4 138 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.
FLT9024-3PH	P1	3 phase fault on the LONGWD 4 (508808) to SCOTTSV4 (508567) 138 kV line CKT 1, near LONGWD 4. a. Apply fault at the LONGWD 4 138 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.

Table 5-3 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9025-3PH	P1	3 phase fault on the NORAM 4 (507774) to RAINES 4 (507749) 138 kV line CKT 1, near NORAM 4. a. Apply fault at the NORAM 4 138 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.
FLT9026-3PH	P1	3 phase fault on the LONGWOOD 138 kV (508808) /345 kV (508809) /13.2 kV (508819) XFMR CKT 1, near LONGWD 4 (508808) 138 kV. a. Apply fault at the LONGWD 4 (508808) 138 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9027-3PH	P1	3 phase fault on the IPCJEFF4 (508833) to JEFFRSN4 (508835) 138 kV line CKT 1, near IPCJEFF4. a. Apply fault at the IPCJEFF4 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.
FLT9028-3PH	P1	3 phase fault on the JEFFRSN4 (508835) to WILKES 4 (508840) 138 kV line CKT 1, near JEFFRSN4. a. Apply fault at the JEFFRSN4 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.
FLT9029-3PH	P1	3 phase fault on the JEFFRSN4 (508835) to LAKEPIN4 (509624) 138 kV line CKT 1, near JEFFRSN4. a. Apply fault at the JEFFRSN4 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.
FLT9030-3PH	P1	3 phase fault on the JEFFRSN4 (508835) to MARSHL-4 (508557) 138 kV line CKT 1, near JEFFRSN4. a. Apply fault at the JEFFRSN4 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.
FLT9031-3PH	P1	3 phase fault on the LONGWD 7 (508809) to SW SHV 7 (507760) 345 kV line CKT 1, near LONGWD 7. a. Apply fault at the LONGWD 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.
FLT9032-3PH	P1	3 phase fault on the LONGWD 7 (508809) to 7SAREPTA% (337376) 345 kV line CKT 1, near LONGWD 7. a. Apply fault at the LONGWD 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.
FLT9033-3PH	P1	3 phase fault on the LONGWD 7 (508809) to WILKES 7 (508841) 345 kV line CKT 1, near LONGWD 7. a. Apply fault at the LONGWD 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.
FLT1001-SB	P4	**Stuck Breaker at NBENTON4 (508811) 138 kV bus** a. Apply single phase fault at NBENTON4 (508811) 138 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the Bus NBENTON4 (508811).

Table 5-3 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1002-SB	P4	**Stuck Breaker at LIEBERM4 (508806) 138 kV bus** a. Apply single phase fault at LIEBERM4 (508806) 138 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the LIEBERM4 (508806) to LONGWD 4 (508808) 138 kV line CKT 1. d. Trip the LIEB 3-1 138 kV (508806) /13.8 kV (509401) XFMR CKT 1. e. Trip the LIEB 3-2 138 kV (508806) /13.8 kV (509401) XFMR CKT 2. Trip generator on bus LIEBR3-1 (509401)
FLT1003-SB	P4	**Stuck Breaker at LIEBERM4 (508806) 138 kV bus** a. Apply single phase fault at LIEBERM4 (508806) 138 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the LIEBERM4 (508806) to IPCJEFF4 (508833) 138 kV line CKT 1. d. Trip the LIEBERM4 (508806) to ARSHILL4 (507711) 138 kV line CKT 1 e. Trip the LIEB 3-1 138 kV (508806) /13.8 kV (509401) XFMR CKT 1. f. Trip the LIEB 3-2 138 kV (508806) /13.8 kV (509401) XFMR CKT 2. g. Trip the LIEBRMN1 138 kV (508806) /69 kV (508805) /13.2 kV (508820) XFMR CKT 1. h. Trip the LIEBRMN2 138 kV (508806) /69 kV (508805) /13.2 kV (508821) XFMR CKT 2. i. Trip the LIEBRMN3 138 kV (508806) /69 kV (508805) /13.2 kV (508822) XFMR CKT 3. Trip generator on bus LIEBR3-1 (509401)
FLT1004-SB	P4	**Stuck Breaker at LIEBERM4 (508806) 138 kV bus** a. Apply single phase fault at LIEBERM4 (508806) 138 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the LIEBERM4 (508806) to IPCJEFF4 (508833) 138 kV line CKT 1. d. Trip the LIEBERM4 (508806) to ARSHILL4 (507711) 138 kV line CKT 1 e. Trip the LIEB 4-1 138 kV (508806) /13.8 kV (509402) XFMR CKT 1. f. Trip the LIEB 4-2 138 kV (508806) /13.8 kV (509402) XFMR CKT 2. g. Trip the LIEBRMN1 138 kV (508806) /69 kV (508805) /13.2 kV (508820) XFMR CKT 1. h. Trip the LIEBRMN2 138 kV (508806) /69 kV (508805) /13.2 kV (508821) XFMR CKT 2. i. Trip the LIEBRMN3 138 kV (508806) /69 kV (508805) /13.2 kV (508822) XFMR CKT 3. Trip generator on bus LIEBR4-1 (509402)
FLT1005-SB	P4	**Stuck Breaker at LIEBERM4 (508806) 138 kV bus** a. Apply single phase fault at LIEBERM4 (508806) 138 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the LIEB 4-1 138 kV (508806) /13.8 kV (509402) XFMR CKT 1. d. Trip the LIEB 4-2 138 kV (508806) /13.8 kV (509402) XFMR CKT 2. e. Trip the LIEBERM4 (508806) to G16-167-TAP (588404) 138 kV line CKT 1. Trip generator on bus LIEBR4-1 (509402)
FLT1006-SB	P4	**Stuck Breaker at LIEBERM4 (508806) 138 kV bus** a. Apply single phase fault at LIEBERM4 (508806) 138 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the LIEBERM4 (508806) to G16-167-TAP (588404) 138 kV line CKT 1. d. Trip the LIEBERM4 (508806) to LONGWD 4 (508808) 138 kV line CKT 1.

5.3 Scenario 1 Results

Table 5-4 shows the relevant results of the fault events simulated for each of the modified models in Scenario 1. Existing DISIS base case issues are documented separately in Appendix C. The associated stability plots are also provided in Appendix C.

Table 5-4: Scenario 1 Dynamic Stability Results (EGF = 0 MW, SGF = 73.88 MW)

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9029-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9030-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9031-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9032-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9033-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable

Table 5-4 continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable

The results of the Scenario 1 dynamic stability showed several existing base case issues that were found in both the original DISIS-2017-002-1 model and the model with GEN-2023-SR23 included. These issues were not attributed to the GEN-2023-SR23 surplus request and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2023-SR23 surplus request 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.

5.4 Scenario 2 Results

Table 5-5 shows the relevant results of the fault events simulated for each of the modified models in Scenario 2. Existing DISIS base case issues are documented separately in Appendix C. The associated stability plots are also provided in Appendix C.

Table 5-5: Scenario 2 Dynamic Stability Results (EGF = 63.5 MW, SGF = 10 MW)

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable

Table 5-5 continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9029-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9030-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9031-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9032-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9033-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable

The results of the Scenario 2 dynamic stability showed several existing base case issues that were found in both the original DISIS-2017-002-1 model and the model with GEN-2023-SR23 included. These issues were not attributed to the GEN-2023-SR23 surplus request and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2023-SR23 surplus request 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.

6.0 Necessary Interconnection Facilities and Network Upgrades

This study identified the impact of the Surplus Interconnection Service on the transmission system reliability and any additional Interconnection Facilities or Network Upgrades necessary. The Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades unless (a) those additional Network Upgrades are either (1) located at the Point of Interconnection substation and at the same voltage level as the Generating Facility with an effective GIA, or (2) are System Protection Facilities; and (b) there are no material adverse impacts on the cost or timing of any Interconnection Requests pending at the time the Surplus Interconnection Service request is submitted.

6.1 Interconnection Facilities

This study did not identify any additional Interconnection Facilities required by the addition of the SGF.

6.2 Network Upgrades

This study did not identify any Network Upgrades required by the addition of the SGF. SPP will reach out to the TO and/or TOP to determine if there are any additional Network Upgrades that are either (1) located at the Point of Interconnection substation and at the same voltage level as the Generating Facility with an effective GIA, or (2) are System Protection Facilities.

7.0 Surplus Interconnection Service Determination and Requirements

In accordance with Attachment V of the SPP Tariff, SPP shall evaluate the request for Surplus Interconnection Service and inform the Interconnection Customer in writing of whether the Surplus Interconnection Service can be utilized without negatively impacting the reliability of the Transmission System and without any additional Network Upgrades necessary except those specified in the SPP Tariff.

7.1 Surplus Service Determination

SPP determined the request for Surplus Interconnection Service does not negatively impact the reliability of the Transmission System and no required Network Upgrades or Interconnection Facilities were identified by this Surplus Interconnection Service Impact Study performed by Aneden. Aneden evaluated the impact of the requested Surplus Interconnection Service on the prior study results and determined that the requested Surplus Interconnection Service resulted in similar dynamic stability and short circuit analyses and that the prior study steady-state results are not negatively impacted.

SPP has determined that GEN-2023-SR23 may utilize the requested 73.5 MW of Surplus Interconnection Service being made available by GEN-2016-167.

7.2 Surplus Service Requirements

The amount of Surplus Interconnection Service available to be used is limited by the amount of Interconnection Service granted to the existing interconnection customer at the same POI. The combined generation from both the SGF and the EGF may not exceed 73.5 MW at the POI, which is the total Interconnection Service amount currently granted to the EGF.

The customer must install monitoring and control equipment as needed to ensure that the SGF does not exceed the granted surplus amount and to ensure that combination of the SGF and EGF power injected at the POI does not exceed the Interconnection Service amount listed in the EGF's GIA. The monitoring and control scheme may be reviewed by the TO and documented in Appendix C of the SGF GIA.

SPP will reach out to the TO and/or TOP to determine if there are any additional Network Upgrades that are either (1) located at the Point of Interconnection substation and at the same voltage level as the Generating Facility with an effective GIA, or (2) are System Protection Facilities.