GEN-2023-SR28

SURPLUS INTERCONNECTION SYSTEM IMPACT STUDY

By SPP Generator Interconnection

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EXECUTIVE SUMMARY

Southwest Power Pool (SPP) was requested by Interconnection Customer (IC) to perform a Surplus Service Impact Study (Study) for GEN-2023-SR28 to utilize the Surplus Interconnection Service being made available by the Fort Dodge 4 project at its existing Point of Interconnection (POI), the Fort Dodge 115kV substation in the Sunflower Electric Company (SUNC) control area.

GEN-2023-SR28, the proposed Surplus Generating Facility (SGF), will connect to its own main collection substation and main power transformer separate from Fort Dodge 4.

Fort Dodge 4, the Existing Generating Facility (EGF), has available surplus capacity of 175 MW and is making 150 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 39 x Sungrow SG4400UD-MV inverters operating at 3.92868 MW for a total assumed dispatch of 150 MW. The inverters are rated at 4.4 MVA, thus the generating capability of the SGF (153.21852 MW) exceeds its requested Surplus Interconnection Service of 150 MW. The injection amount of the SGF must be limited to 150 MW at the POI. The combined generation from both the SGF and the EGF may not exceed 175 MW at the POI. GEN-2023-SR28 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 1.

The detailed SGF configuration is captured in Table 2.

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

Table 1: EGF & SGF Configuration

REQUEST	POINT OF INTERCONNECTION	EXISTING GENERATOR CONFIGURATION	CAPACITY (MW)
GEN-2023-SR28 (SGF)	Fort Dodge 115kV	9 x Sungrow SG4400UD-MV Inverters	150
Fort Dodge 4 (EGF)		Steam gas turbine	175

Table 2: SGF Interconnection Configuration

FACILITY	SGF CONFIGURATION
Point of Interconnection	Fort Dodge 115kV (539671)
Configuration/Capacity	39 x Sungrow SG4400UD-MV operating at 3.92868 MW () = 153.219 MW [dispatch] Units are rated at 4.4 MVA, **PPC to limit GEN-2023-SR28 to 150 MW** at the POI and **total POI injection with Fort Dodge 4 to 175 MW**
Generation Interconnection Line (Shared with the EGF per the DISIS-2017-002-1 models and unchanged)	Length = 2.983 miles R = 0.00148488 pu X = 0.010564 pu B = 0.00363 pu Rating MVA = 288.879 MVA
Main Substation Transformer[1] (Shared with the EGF per the DISIS-2017-002-1 models and unchanged)	X = 8.99766%, R = 0.21423% Winding MVA = 111 MVA, Rating MVA = 185 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 39 X = 4.63239%, R = 0.52462% Winding MVA = 171.6 MVA, Rating MVA2 = 171.6 MVA
Generator Dynamic Model[2] & Power Factor	39 x Sungrow SG4400UD-MV (REGCAU1)[3] Leading: 0.8 Lagging: 0.8
Reactive Power Devices (Shared with the EGF per the DISIS-2017-002-1 models and unchanged)	1 x 12 MVAR 34.5 kV Reactor 4 x 15 MVAR 34.5 kV Capacitor Bank

SPP determined that steady-state analysis was not required because the addition of the SGF does not increase the maximum active power output of 150 MW. Since the EGF was a Legacy unit and was not subject to a DISIS steady-state analysis, no powerflow analysis for the EGF is required.

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

SPP 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 34.8.0 software and the results are summarized below.

The results of the reactive power analysis using the 25SP model showed that the SGF project needed a 3.3 MVAR 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 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 0.972 kA. The maximum three-phase fault current level within five buses of the POI with the EGF and SGF generators online was below 17 kA for the 25SP model. There were no buses with a maximum three-phase fault current over 40 kA.

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. 48 events were simulated, which included three-phase faults and single-line-to-ground stuck breaker faults.

- Scenario 1: SGF at maximum assumed dispatch, 150 MW, and EGF disconnected.

[2] Power System Simulator for Engineering

- Scenario 2: SGF at maximum assumed dispatch, 150 MW, and EGF dispatched with the remaining 25 MW for a total combination of 175 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-SR28 included. These issues were not attributed to the GEN-2023-SR28 surplus request and are detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2023-SR28 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-SR28 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-SR28 may utilize the requested 150 MW of Surplus Interconnection Service being made available by the EGF. The combined generation from both the SGF and the EGF may not exceed 175 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.

SCOPE OF STUDY

Southwest Power Pool (SPP) was requested by Interconnection Customer (IC) to perform a Surplus Service Impact Study (Study) for GEN-2023-SR28, 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®[4] version 34.8.0 software. The results of each analysis are presented in the following sections.

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.

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,

[3] Allowed Network Upgrades detailed in SPP Open Access Transmission Tariff Attachment V Section 3.3
[4] Power System Simulator for Engineering

along with the amount of increase in maximum fault current due to the addition of the SGF. The analysis was performed on two scenarios: one with the EGF in service and SGF offline and one the modified model with both EGF and SGF in service.

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 where the SGF was online at 100% of the assumed dispatch and the EGF was picking up the remaining EGF GIA capacity. The stability analyses will identify any additional Interconnection Facilities and Network Upgrades necessary.

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 subject to SPP powerflow study, yet 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 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.

NECESSARY INTERCONNECTION FACILITIES & NETWORK UPGRADES

The SPP Tariff[5] 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

[5] SPP Open Access Transmission Tariff Section 3.3.4.1

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.

STUDY LIMITATIONS

The assessments and conclusions provided in this report are based on assumptions and information provided to SPP by others. While the assumptions and information provided may be appropriate for the purposes of this report, SPP does not guarantee that those conditions assumed will occur. In addition, SPP 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.

SURPLUS INTERCONNECTION SERVICE REQUEST

The GEN-2023-SR28 Interconnection Customer has requested a Surplus Interconnection Service Impact Study (Study) for GEN-2023-SR28 to utilize the Surplus Interconnection Service being made available by the Fort Dodge 4 project at its existing Point of Interconnection (POI), Fort Dodge 4 115 kV in the Sunflower Electric Company (SUNC) control area.

GEN-2023-SR28, the proposed SGF, will connect to the existing Fort Dodge substation utilizing its own main power transformer separate from the EGF.

Fort Dodge 4, the EGF, has an effective Generation Interconnection Agreement (GIA) with a combined POI capacity of 175 MW and is making 150 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, Fort Dodge 4 (EGF) is an active existing project at the same POI (Fort Dodge 115 kV) that was installed onto the Transmission System prior to SPP's Interconnection Queue. The Fort Dodge 4 project is a gas unit and has a maximum capacity of 175 MW. Figure 1 shows the power flow model single line diagram for the EGF configuration.

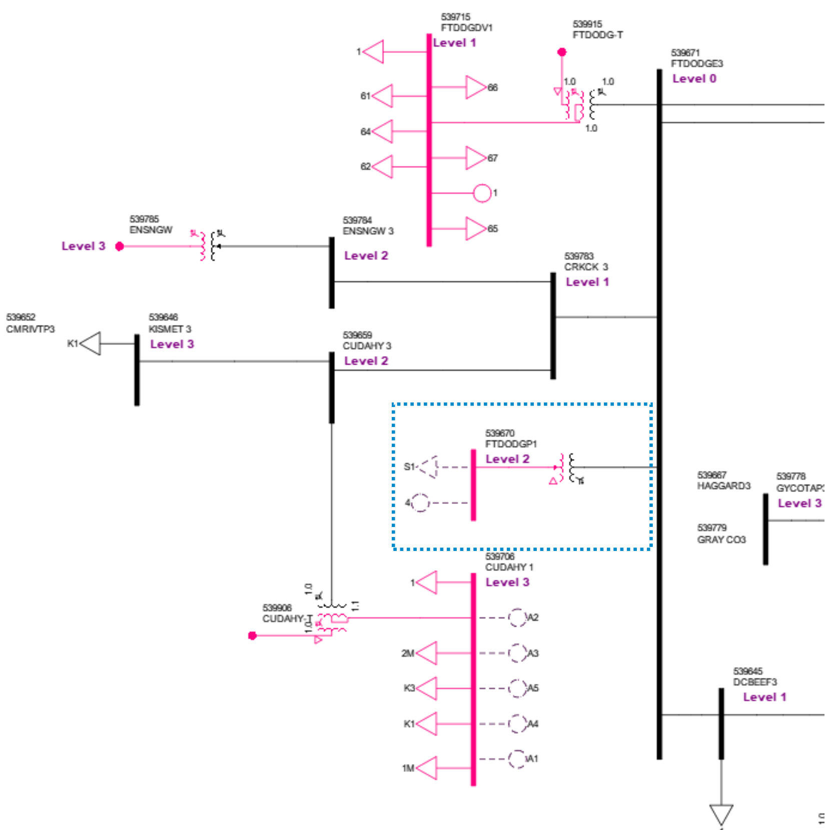
The proposed SGF configuration consists of 39 x Sungrow SG4400UD-MV inverters operating at 3.92868 MW for a total assumed dispatch of 150 MW. The inverters are rated at 4.4 MVA, thus the generating capability of the SGF (153.21852 MW) exceeds its requested Surplus Interconnection Service of 150 MW. The injection amount of the SGF must be limited to 150 MW at the POI. The combined generation from both the SGF and the EGF may not exceed 175 MW at the POI. GEN-2023-SR28 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 3.

Table 3: EGF & SGF Configuration

REQUEST	POINT OF INTERCONNECTION	EXISTING GENERATOR CONFIGURATION	CAPACITY (MW)
GEN-2023-SR28 (SGF)	Fort Dodge 115kV	39 x Sungrow SG4400UD-MV Inverters	150
Fort Dodge 4 (EGF)		Steam gas turbine	175

The proposed detailed SGF configuration is captured in Figure 2 and Table 4.

Figure 1: Fort Dodge 4 Single Line Diagram (EGF Existing Configuration*)



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

SPP Internal Only

Figure 2: Fort Dodge 4 & GEN-2023-SR28 Single Line Diagram (EGF & SGF Configuration)

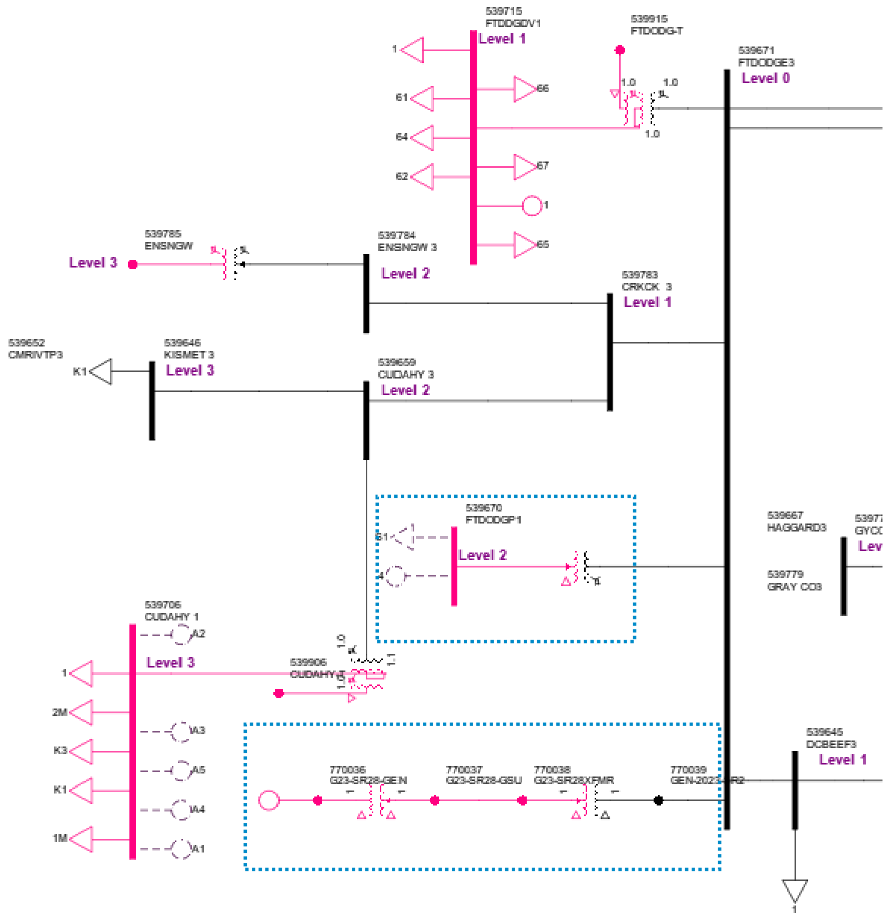


Table 4: SGF Interconnection Configuration

FACILITY	SGF CONFIGURATION
Point of Interconnection	Fort Dodge 115kV (539671)
Configuration/Capacity	39 x Sungrow SG4400UD-MV operating at 3.92868 MW () = 153.219 MW [dispatch] Units are rated at 4.4 MVA, **PPC to limit GEN-2023-SR28 to 150 MW** at the POI and **total POI injection with Fort Dodge 4 to 175 MW**
Generation Interconnection Line (Shared with the EGF per the DISIS-2017-002-1 models and unchanged)	Length = 2.983 miles R = 0.00148488 pu X = 0.010564 pu B = 0.00363 pu Rating MVA = 288.879 MVA
Main Substation Transformer[1] (Shared with the EGF per the DISIS-2017-002-1 models and unchanged)	X = 8.99766%, R = 0.21423% Winding MVA = 111 MVA, Rating MVA = 185 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 39 X = 4.63239%, R = 0.52462% Winding MVA = 171.6 MVA, Rating MVA2 = 171.6 MVA
Generator Dynamic Model[2] & Power Factor	39 x Sungrow SG4400UD-MV (REGCAU1)[3] Leading: 0.8 Lagging: 0.8
Reactive Power Devices (Shared with the EGF per the DISIS-2017-002-1 models and unchanged)	1 x 12 MVAR 34.5 kV Reactor 4 x 15 MVAR 34.5 kV Capacitor Bank

REACTIVE POWER ANALYSIS

The reactive power analysis was performed for GEN-2023-SR28 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.

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 and capacitors 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).

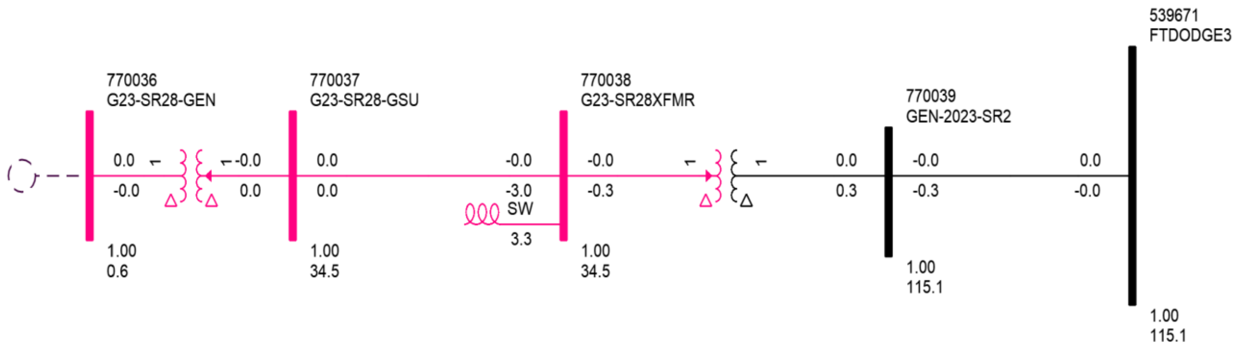
SPP performed the reactive power analysis using the SGF data based on the 25SP DISIS-2017-002-1 stability study model.

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 3.3 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 needed a 3.3 MVAR shunt reactor. Figure 3 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: GEN-2023-SR28 Single Line Diagram (Shunt Sizes)



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.

METHODOLOGY

The short circuit analysis included applying a three-phase fault on buses up to five 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 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.

SPP 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 5. No other changes were made to the model.

Table 5: Short Circuit Model Parameters*

PARAMETER	VALUE BY GENERATOR BUS#	
	770036	539670
Machine MVA Base	220	175
R (pu)	0.0	0.0
X'' (pu)	0.64218	0.164

*pu values based on Machine MVA Base

SCENARIO 1 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-SR28 POI bus (Fort Dodge 4 115 kV - 539671) fault current magnitudes for the comparison cases are provided in Table 6 showing a fault current of 9.892 kA with the EGF and SGF online. The addition of the SGF configuration increased the POI bus fault current by 0.972 kA. Table 7 shows the maximum fault current magnitudes and fault current increases with the SGF project online.

The maximum fault current calculated within five buses of the POI was less than 17 kA for the 25SP model. There were no buses with a maximum three-phase fault current over 40 kA. The maximum contribution to three-phase fault currents due to the addition of the SGF was about 10.9% and 0.972 kA.

Table 6: POI Short-Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
25SP	8.92	9.892	0.972	10.9%

Table 7: 25SP Short-Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
115	12.696	0.992	13.23%
230	12.153	0.149	1.24%
345	16.057	0.152	1.19%
Max	**16.057**	**0.992**	**13.23%**

SCENARIO 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-SR28 POI bus (Fort Dodge 4 115 kV - 539671) fault current magnitudes for the comparison cases are provided in Table 6 showing a fault current of 13.344 kA with the EGF and SGF online. The addition of the SGF configuration increased the POI bus fault current by 4.424 kA. Table 7 shows the maximum fault current magnitudes and fault current increases with the SGF project online.

The maximum fault current calculated within five buses of the POI was less than 17 kA for the 25SP model. There were no buses with a maximum three-phase fault current over 40 kA. The maximum contribution to three-phase fault currents due to the addition of the SGF was about 49.6% and 4.424 kA.

Table 8: POI Short-Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
25SP	8.92	13.344	4.424	49.6%

Table 9: 25SP Short-Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
115	13.368	4.424	49.6%
230	12.525	0.521	4.34%
345	16.134	0.53	4.15%
Max	**16.134**	**4.424**	**49.6%**

DYNAMIC STABILITY ANALYSIS

SPP performed a dynamic stability analysis to identify the impact of the SGF project. The analysis was performed according to SPP's Disturbance Performance Requirements[6]. The project details are described in the *Surplus Interconnection Service Request* section and the dynamic modeling data is provided in Appendix A. The existing base case issues and simulation plots can be found in Appendix C.

METHODOLOGY AND CRITERIA

The dynamic stability analysis was performed using models developed with the requested 39 x Sungrow SG4400UD-MV battery energy storage system () inverters operating at 3.92868 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 = 150 MW) while the EGF generator was offline and disconnected. The second scenario (Scenario 2) was comprised of the SGF at 100% of the assumed dispatch (SGF = 150 MW) while the EGF generator picked up the remaining EGF GIA capacity (EGF = 25 MW). The study scenarios are shown in Table 10.

Table 10: Study Scenarios (Generator Dispatch MW)

SCENARIO	FORT DODGE 4 EGF (MW)	GEN-2023-SR28 SGF (MW)	EGF + SGF (MW)
1	0 (Offline)	150	150
2	25	150	175

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

The GEN-2023-SR28 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-SR28 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 frequency protective relays at buses 53984501, 53984601, 53984701, 53984801, 53985201, 53985301, 53912101, 53912302, 53984502, 53984602, 53984702, 53984802, 53985202, 53985302, 53912102, 53912302, 53984511, 53984611, 53984711, 53984811, 53985211, 53985311, 53991802, 53911104, 53912307, 53994905, 53912308 were disabled after observing the generators tripping during initial three phase fault simulations. This frequency tripping issue is a known PSS/E limitation when calculating bus frequency as it relates to non-conventional type devices.
- The voltage protective relays at buses 53912301, 53912303, 53912304, 77003609, 53913607, 53984516, 53984616, 53984716, 53984816, 53912309, 53911111, 53994809, 53994914, 53912305, 53994903, 53911105, 53994803, 53912306, 53994904, 65945306 were disabled to avoid generator tripping due to an instantaneous over voltage spike after fault clearing.
- The fault simulation file acceleration factor was reduced as needed to resolve stability simulation crashes.

During the fault simulations, the study requests and other generation within the cluster group, adjacent powerflow areas, and within five buses away were monitored for compliance with the SPP Disturbance Performance Criteria. The machine rotor angle for synchronous machines within the study areas including 524 (OKGE), 525 (WFEC), 526 (SPS), 531 (MIDW), 534 (SUNC), 536 (WERE), 541 (KCPL), 542 (KACY), 544 (EMDE), 545 (INDN), 546 (SPRM), and 640 (NPPD) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

FAULT DEFINITIONS

SPP 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 11. These contingencies were applied to the modified 25SP and 25WP models.

Table 11: Fault Definitions

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT9001-3PH	P1	3 phase fault on the FTDODGE3 115kV (539671)/ 34.5 kV (539715)/ 2.4 kV (539915) XFMR 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 XFMR.
FLT9002-3PH	P1	3 phase fault on the FTDODGE3 (539671) to NFTDODG3 (539771) 115 kV line CKT 2, 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.
FLT9003-3PH	P1	3 phase fault on the FTDODGE3 (539671) to CRKCK 3 (539783) 115 kV line CKT 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.
FLT9004-3PH	P1	3 phase fault on the FTDODGE3 (539671) to DCBEEF3 (539645) 115 kV line CKT 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.
FLT9005-3PH	P1	3 phase fault on the NFTDODG3 (539771) to SPRVL 3 (539759) 115 kV line CKT 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.
FLT9006-3PH	P1	3 phase fault on the NFTDODG3 (539771) to SPEARVL3 (539694) 115 kV line CKT 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.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9007-3PH	P1	3 phase fault on the NFTDODG3 (539771) to FORD 3 (539758) 115 kV line CKT 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.
FLT9008-3PH	P1	3 phase fault on the NFTDODG3 (539771) to S-DODGE3 (539688) 115 kV line CKT 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.
FLT9009-3PH	P1	3 phase fault on the DCBEEF3 (539645) to EDODGE 3 (539740) 115 kV line CKT 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.
FLT9010-3PH	P1	3 phase fault on the CRKCK 3 (539783) to CUDAHY 3 (539659) 115 kV line CKT 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.
FLT9011-3PH	P1	3 phase fault on the CRKCK 3 (539783) to ENSNGW 3 (539784) 115 kV line CKT 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.
FLT9012-3PH	P1	3 phase fault on the SPRVL 3 115kV (539759)/ 345 kV (531469)/ 13.8 kV (539960) XFMR 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 XFMR.
FLT9013-3PH	P1	3 phase fault on the SPRVL3 115kV (539694)/ 230 kV (539695)/ 13.8 kV (539935) XFMR CKT 1, near SPRVL3 115 kV. a. Apply fault at the SPRVL3 115 kV bus. b. Clear fault after 7 cycles and trip the faulted XFMR.
FLT9014-3PH	P1	3 phase fault on the FORD 3 (539758) to SSTARTP3 (539763) 115 kV line CKT 1, near FORD 3. a. Apply fault at the FORD 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.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT9015-3PH	P1	3 phase fault on the S-DODGE3 (539688) to W-DODGE3 (539699) 115 kV line CKT 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.
FLT9016-3PH	P1	3 phase fault on the W-DODGE3 (539699) to GYCOTAP3 (539778) 115 kV line CKT 1, near W-DODGE3. a. Apply fault at the W-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.
FLT9017-3PH	P1	3 phase fault on the W-DODGE3 (539699) to NW-DGTP3 (539628) 115 kV line CKT 1, near W-DODGE3. a. Apply fault at the W-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.
FLT9018-3PH	P1	3 phase fault on the EDODGE 3 (539740) to N-DODGE3 (539680) 115 kV line CKT 1, near EDODGE 3. a. Apply fault at the EDODGE 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.
FLT9019-3PH	P1	3 phase fault on the CUDAHY 3 115kV (539659)/ 34.5 kV (539706)/ 13.8 kV (539906) XFMR 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 XFMR.
FLT9020-3PH	P1	3 phase fault on the SPERVIL7 (531469) to BUCKNER7 (531501) 345 kV line CKT 1, near SPERVIL7. a. Apply fault at the SPERVIL7 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.
FLT9021-3PH	P1	3 phase fault on the SPERVIL7 345kV (531469)/ 230 kV (539695)/ 13.8 kV (531468) XFMR CKT 1, near SPERVIL7 345 kV. a. Apply fault at the SPERVIL7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT9022-3PH	P1	3 phase fault on the SPERVIL7 (531469) to G16-049-TAP (589484) 345 kV line CKT 1, near SPERVIL7. a. Apply fault at the SPERVIL7 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.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT9023-3PH	P1	3 phase fault on the SPERVIL7 (531469) to IRONWOOD7 (539803) 345 kV line CKT 1, near SPERVIL7. a. Apply fault at the SPERVIL7 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.
FLT9024-3PH	P1	3 phase fault on the SPERVIL7 (531469) to CLARKCOUNTY7 (539800) 345 kV line CKT 1, near SPERVIL7. a. Apply fault at the SPERVIL7 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.
FLT9025-3PH	P1	3 phase fault on the CLARKCOUNTY7 (539800) to G16-046-TAP (560080) 345 kV line CKT 1, near CLARKCOUNTY7. a. Apply fault at the CLARKCOUNTY7 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.
FLT9026-3PH	P1	3 phase fault on the SSTARTP3 (539763) to GRNBURG3 (539664) 115 kV line CKT 1, near SSTARTP3. a. Apply fault at the SSTARTP3 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.
FLT9027-3PH	P1	3 phase fault on the SSTARTP3 (539763) to SSTARW 3 (539761) 115 kV line CKT 1, near SSTARTP3. a. Apply fault at the SSTARTP3 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.
FLT9028-3PH	P1	3 phase fault on the N-DODGE3 (539680) to NW-DODG3 (539641) 115 kV line CKT 1, near N-DODGE3. a. Apply fault at the N-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.
FLT9029-3PH	P1	3 phase fault on the CUDAHY 3 (539659) to KISMET 3 (539646) 115 kV line CKT 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.
FLT9030-3PH	P1	3 phase fault on the BUCKNER7 (531501) to CIMRRN 7 (531502) 345 kV line CKT 1, near BUCKNER7. a. Apply fault at the BUCKNER7 345 kV bus.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		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.
FLT9031-3PH	P1	3 phase fault on the BUCKNER7 (531501) to CIMWD2 7 (531504) 345 kV line CKT 1, near BUCKNER7. a. Apply fault at the BUCKNER7 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 BUCKNER7 (531501) to HOLCOMB7 (531449) 345 kV line CKT 1, near BUCKNER7. a. Apply fault at the BUCKNER7 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 G16-049-TAP (589484) to POSTROCK7 (530583) 345 kV line CKT 1, near G16-049-TAP. a. Apply fault at the G16-049-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9034-3PH	P1	3 phase fault on the IRONWOOD7 (539803) to GEN-2008-124 (579480) 345 kV line CKT 1, near IRONWOOD7. a. Apply fault at the IRONWOOD7 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.
FLT9035-3PH	P1	3 phase fault on the IRONWOOD7 (539803) to G16-046-TAP (560080) 345 kV line CKT 1, near IRONWOOD7. a. Apply fault at the IRONWOOD7 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.
FLT9036-3PH	P1	3 phase fault on the IRONWOOD7 (539803) to IRONWOOD WF7 (539815) 345 kV line CKT 1, near IRONWOOD7. a. Apply fault at the IRONWOOD7 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.
FLT9037-3PH	P1	3 phase fault on the SPEARVL6 (539695) to SPRVILL-EHVB (539117) 230 kV line CKT Z1, near SPEARVL6. a. Apply fault at the SPEARVL6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT9038-3PH	P1	3 phase fault on the SPEARVL6 (539695) to GRTBEND6 (539679) 230 kV line CKT 1, near SPEARVL6. a. Apply fault at the SPEARVL6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT1001-SLG	P4	Apply single-phase fault at FTDODGE3 on the 115kV bus after 16 cycles a. Trip the FTDODGE3 to DCBEEF3 Transmission Line Ckt 1 b. Trip the FTDODGE3 to NFTDODG3 Transmission Line Ckt 1
FLT1002-SLG	P4	Apply single-phase fault at FTDODGE3 on the 115kV bus after 16 cycles a. Trip the FTDODGE3 to NFTDODG3 Transmission Line Ckt 1 b. Trip the FTDODGE3 115/15kV Transformer Ckt 1
FLT1003-SLG	P4	Apply single-phase fault at FTDODGE3 on the 115kV bus after 16 cycles a. Trip the FTDODGE3 115/15kV Transformer Ckt 1 b. Trip the FTDODGE3 to CRKCK 3 Transmission Line Ckt 1
FLT1004-SLG	P4	Apply single-phase fault at FTDODGE3 on the 115kV bus after 16 cycles a. Trip the FTDODGE3 to CRKCK 3 Transmission Line Ckt 1 b. Trip the FTDODGE3 to NFTDODG3 Transmission Line Ckt 2
FLT1005-SLG	P4	Apply single-phase fault at FTDODGE3 on the 115kV bus after 16 cycles a. Trip the FTDODGE3 to NFTDODG3 Transmission Line Ckt 2 b. Trip the FTDODGE3 115/34.5/2.4kV Transformer Ckt 1
FLT1006-SLG	P4	Apply single-phase fault at FTDODGE3 on the 115kV bus after 16 cycles a. Trip the FTDODGE3 115/34.5/2.4kV Transformer Ckt 1 b. Trip the FTDODGE3 to DCBEEF3 Transmission Line Ckt 1
FLT1008-SLG	P4	Apply single-phase fault at NFTDODG3 on the 115kV bus after 16 cycles a. Trip the NFTDODG3 to FTDODGE3 Transmission Line Ckt 1 b. Trip the NFTDODG3 to S-DODGE3 Transmission Line Ckt 1
FLT1009-SLG	P4	Apply single-phase fault at NFTDODG3 on the 115kV bus after 16 cycles a. Trip the NFTDODG3 to FTDODGE3 Transmission Line Ckt 2 b. Trip the NFTDODG3 to SPRVL 3 Transmission Line Ckt 1
FLT1010-SLG	P4	Apply single-phase fault at NFTDODG3 on the 115kV bus after 16 cycles a. Trip the NFTDODG3 to FORD 3 Transmission Line Ckt 1 b. Trip the NFTDODG3 to SPEARVL3 Transmission Line Ckt 1
FLT1011-SLG	P4	Apply single-phase fault at CRKCK 3 on the 115kV bus after 16 cycles a. Trip the CRKCK 3 to CUDAHY 3 Transmission Line Ckt 1 b. Trip the CRKCK 3 to FTDODGE3 Transmission Line Ckt 1
FLT1012-SLG	P4	Apply single-phase fault at DCBEEF3 on the 115kV bus after 16 cycles a. Trip the DCBEEF3 to FTDODGE3 Transmission Line Ckt 1 b. Trip the DCBEEF3 to EDODGE 3 Transmission Line Ckt 1

SCENARIO 1 RESULTS

Table 12 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 12: Scenario 1 Dynamic Stability Results (EGF = 0 MW, SGF = 150 MW)

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT 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

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	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

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	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
FLT9034-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9035-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9036-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9037-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9038-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SLG	Pass	Pass	Stable	Pass	Pass	Stable

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT1008-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1012-SLG	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-SR28 included. These issues were not attributed to the GEN-2023-SR28 surplus request and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2023-SR28 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.

SCENARIO 2 RESULTS

Table 13 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 13: Scenario 2 Dynamic Stability Results (EGF = 25 MW, SGF = 150 MW)

FAULT ID	25SP	25WP

	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT 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

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	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

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT9034-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9035-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9036-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9037-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9038-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1012-SLG	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-SR28 included. These issues were not attributed to the GEN-2023-SR28 surplus request and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2023-SR28 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.

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.

INTERCONNECTION FACILITIES

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

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.

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.

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 SPP. SPP 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-SR28 may utilize the requested 150 MW of Surplus Interconnection Service being made available by Fort Dodge 4.

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 175 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.