GEN-2023-GR2

GENERATOR REPLACEMENT STUDY

By Aneden Consulting and SPP Generator Interconnection

Published on 04/30/2024

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
04/29/2024	Aneden Consulting & SPP Staff	Original Version	

CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDICES

EXECUTIVE SUMMARY

Pursuant to the Southwest Power Pool (SPP) Open Access Transmission Tariff (SPP tariff) Attachment V section 3.9 and SPP Business Practice 7800, Interconnection Customers can submit replacement requests for its Existing Generating Facilities. The Interconnection Customer of an Existing Generating Facility (EGF) with a Point of Interconnection (POI) at the Tinker Air Force Base 138 kV Substation requested to be studied in the SPP Generator Replacement process.

GEN-2023-GR2, the Replacement Generating Facility (RGF), will connect to the existing POI, the Tinker Air Force Base 138 kV Substation in the Oklahoma Gas & Electric (OG&E) area.

The EGF has 95.504 MW of available replacement capacity, based on the nameplate of the generating facility provided by the Interconnection Customer. This study has been requested to evaluate impact of the RGF, consisting of 2 x BDAX 7-290ERJT 71.176 MVA synchronous gas-fired units with a total assumed dispatch of 86.846/96.162 MW Summer/Winter. This generating capability for the RGF exceeds its requested Interconnection Service amount of a summer capacity of 84.926 MW and winter capacity of 94.242 MW at the POI. As a result, the customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount. To operate above these amounts, a new Interconnection Request would need to be submitted.

The Generator Replacement Process consists of two parts: a Reliability Assessment Study and a Replacement Impact Study. The Reliability Assessment Study identifies any system impacts after the removal of the EGF from service and before the commission date of the RGF with proposed system adjustments to mitigate any issues. The Replacement Impact Study evaluates whether the RGF is a Material Modification.

Reliability Assessment Study

Because the EGF was considered retired prior to the Generating Facility Replacement, the performance of the Transmission System with the EGF ceasing commercial operations is the status quo. SPP determined that for the Reliability Assessment Study, no further analysis for the time between removing from service of the EGF and the commission of the RGF is necessary, and no mitigations are applicable.

Replacement Impact Study

Aneden Consulting (Aneden) was retained by SPP to perform the Replacement Impact Study (Impact Study) for GEN-2023-GR2.

SPP determined that steady-state analysis was not required as the EGF is a Legacy unit and as such was not subject to a DISIS steady-state analysis. Since the RGF is a synchronous generator, a reactive power analysis was not required.

However, SPP determined that short circuit and dynamic stability analyses were required as the dynamic model for the EGF and RGF are different (GENROU [EGF] and GENTPJU1 [RGF]). The scope of this Impact Study included short circuit analysis and dynamic stability analysis.

The results of the Impact Study showed that the requested replacement did not have a material adverse impact on the SPP transmission system. The requested generator replacement of the EGF with GEN-2023-GR2 was determined **not a Material Modification**.

As the requested replacement generating capacity is higher than its Interconnection Service, the customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the requested Interconnection Service amount. The monitoring and control scheme may be reviewed by the Transmission Owner (TO) and documented in Appendix C of the RGF GIA.

It is likely that the customer may be required to reduce its generation output 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. Transfer of an existing resource designation from the EGF to the RGF can be achieved by submitting a transfer of designation request pursuant to Section 30.2.1 of the SPP tariff. If the customer would like to obtain new deliverability to final customers, a separate request for transmission service must be requested on SPP’s OASIS by the customer.

SCOPE OF STUDY

Pursuant to SPP tariff Attachment V section 3.9 and SPP Business Practice 7800, Interconnection Customers can submit replacement requests for its Existing Generating Facilities. A Generator Replacement Impact Study is an interconnection study performed to evaluate the impacts of replacing existing generation with new generation. Two analyses covering different time frames are evaluated:

- Reliability Assessment Study – study performed to evaluate the performance of the Transmission System for the period between the date that the Existing Generating Facility (EGF) ceases commercial operations and the Commercial Operation Date (COD) of the Replacement Generating Facility (RGF).

- Replacement Impact Study – study performed to evaluate if the RGF has a material adverse impact on the SPP Transmission System.

For any impacts to the system identified in the Reliability Assessment Study, non-transmission solutions such as redispatch, remedial action schemes, or reactive setting adjustments will be identified to mitigate issues originating after the removal of the EGF from service and before the commission of the RGF.

If the Replacement Impact Study identifies any materially adverse impact from operating the RGF when compared to the EGF, such impacts shall be deemed a Material Modification.

RELIABILITY ASSESSMENT STUDY

The Reliability Assessment Study, for the time period between the date that the EGF ceases commercial operations and the Commercial Operation Date of the RGF, evaluates the performance of the Transmission System.

This study compares the conditions on the Transmission System that would exist if the EGF is taken offline to the conditions on the Transmission System as they exist when the EGF is online. The EGF would be responsible for mitigating any reliability violation identified in the study and may not cease operations until all mitigations are implemented or are in service.

Because the EGF was considered retired prior to the Generating Facility Replacement and was out-of-service in the latest planning assessment models, the performance of the Transmission System with the EGF ceasing commercial operations is the status quo. SPP determined that for the Reliability Assessment Study, no further analysis for the time between removing from service of the EGF and the commission of the RGF is necessary, and no mitigations are applicable.

REPLACEMENT IMPACT STUDY

Aneden Consulting (Aneden) was retained by SPP to perform the Replacement Impact Study (Impact Study) for GEN-2023-GR2. All analyses were performed using Siemens PTI PSS/E version 34 software.

STEADY STATE ANALYSIS

To determine whether steady state analysis is required, SPP evaluates the reliability conditions that were previously studied. This is done by comparing the current DISIS steady-state requirements versus the steady-state analysis previously performed on the EGF. SPP determined that since the EGF was a Legacy unit and was not subject to a DISIS steady-state analysis, no steady-state analysis for the RGF is required.

STABILITY AND SHORT CIRCUIT ANALYSES

To determine whether stability and short circuit analyses are required, SPP evaluates the difference between the stability models and corresponding parameters and, if needed, the collector system impedance between the existing configuration and the requested replacement. Dynamic stability analysis and short circuit analysis shall be performed if the differences listed above may result in a significant impact on the most recently performed DISIS stability analysis.

REACTIVE POWER ANALYSIS

The reactive power analysis determines the capacitive effect at the POI caused by the project's collector system and transmission line's capacitance. A shunt reactor size is determined in order to offset the capacitive effect and maintain zero (0) MVAr flow at the POI while the project's generators and capacitors (if any) are offline. A reactive power analysis was not performed on the requested replacement configuration as it is a synchronous generator resource.

STUDY LIMITATIONS

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

PROJECT AND REPLACEMENT REQUEST

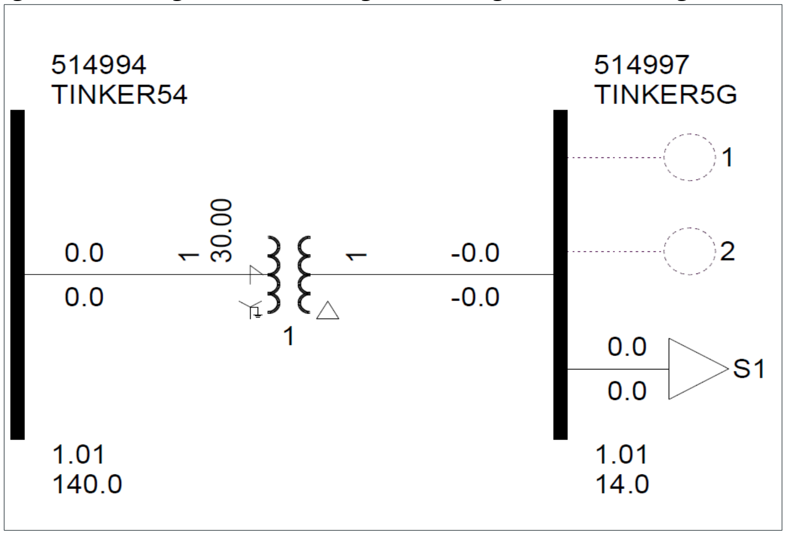
The GEN-2023-GR2 Interconnection Customer has requested a replacement to its EGF, a synchronous gas-fired generating facility with a POI at the Tinker Air Force Base 138 kV Substation and a requested retirement date of April 1, 2026. The Interconnection Service available for replacement is 95.504 MW, based on the nameplate of the generating facility provided by the Interconnection Customer. Of the Interconnection Service available, the RGF Interconnection Customer has requested 84.926/94.242 MW Summer/Winter MW of Energy Resource Interconnection Service (ERIS). The requested RGF is a synchronous gas-fired generation plant consisting of 2 x BDAX 7-290ERJT 71.176 MVA synchronous gas-fired units with a total assumed dispatch of 86.846/96.162 MW Summer/Winter MW. This generating capability for the RGF exceeds its requested Interconnection Service amount of a summer capacity of 84.926 MW and winter capacity of 94.242 MW at the POI. As a result, the customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount. To operate above these amounts, a new Interconnection Request would need to be submitted.

The RGF has a planned commercial operation date of May 1, 2026. The EGF predated the SPP GI queue and does not have an SPP Generation Interconnection Agreement (GIA).

The POI of the EGF and RGF is at the Tinker Air Force Base 138 kV Substation in the Oklahoma Gas & Electric (OG&E) area, and the EGF and RGF are not expected to be operational simultaneously. Figure 1 and Figure 2 show the steady state model single-line diagram for the EGF and RGF configurations, respectively. Table 1 details the existing and replacement configurations for GEN-2023-GR2.

Because the Interconnection Customer requested less Interconnection Service for the RGF than was made available by the EGF, the remaining capacity is assumed unused as part of this replacement request. Should the Interconnection Customer choose to proceed with this replacement, the remaining unused capacity would be subject to a separate replacement request such that the total replacement capacity does not exceed this amount and other requirements from SPP tariff Attachment V section 3.9 are met.

Figure 1: Existing Generation Single Line Diagram (EGF Configuration)*



*based on the DISIS-2018-002/2019-001 25SP stability models

Figure 2: GEN-2023-GR2 Single Line Diagram (RGF Configuration)

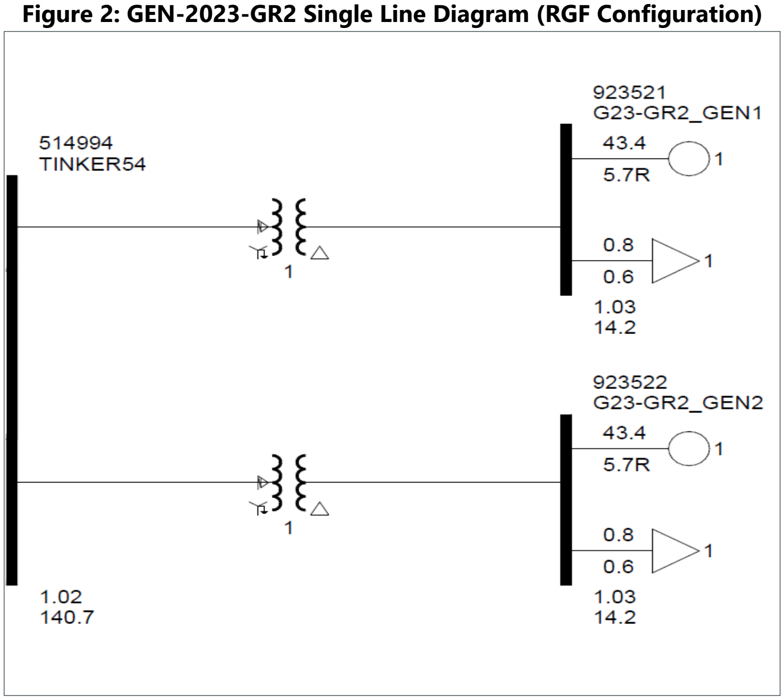


Table 1: EGF and RGF Configuration Details

Facility	Existing Generator Facility Configuration		Replacement Generator Facility Configuration	
Point of Interconnection	Tinker Air Force Base 138 kV (TINKER54 138 kV 514994)		Tinker Air Force Base 138 kV (TINKER54 138 kV 514994)	
Configuration/Capacity	2 Synchronous Gas-Fired Units with a combined capability of 95.504 MW		2 x BDAX 7-290ERJT 71.176 MVA Gas Combustion Turbines = 142.352 MVA [86.846/96.162 MW Summer/Winter dispatch] POI limited to 84.926/94.242 MW Summer/Winter	
Generator Step Up Transformer[1]	X = 12.84%, R = 0.66%,		X = 9.994%, R = 0.345%,	X = 9.994%, R = 0.345%,
	Voltage = 13.8/144.9 kV		Voltage = 13.8/138 kV (Delta/Wye),	Voltage = 13.8/138 kV (Delta/Wye),
	Winding MVA = 100 MVA,		Fixed Taps Available = 5 Taps, ±5%	Fixed Taps Available = 5 Taps, ±5%
	Rating MVA = 78 MVA		Winding MVA = 42 MVA,	Winding MVA = 42 MVA,
			Rating MVA = 75 MVA	Rating MVA = 75 MVA
Auxiliary Load	0 MW + 0 MVAr on 13.8 kV bus		0.7763 MW + 0.595 MVAr on 13.8 kV bus	0.7763 MW + 0.595 MVAr on 13.8 kV bus
Generator Dynamic Model[2] & Power Factor	GENROU[2]	GENROU[2]	1 x BDAX 7-290ERJT 71.176 MVA (GENTPJU1)[2]	1 x BDAX 7-290ERJT 71.176 MVA (GENTPJU1)[2]
	Leading: 0.93	Leading: 0.94	Leading: 0.86/0.88 [Summer/Winter]	Leading: 0.86/0.88 [Summer/Winter]
	Lagging: 0.9	Lagging: 0.89	Lagging: 0.77/0.675 [Summer/Winter]	Lagging: 0.77/0.675 [Summer/Winter]
1) X and R based on Winding MVA, 2) DYR stability model name				

Because the Interconnection Customer requested less Interconnection Service for the RGF than was made available by the EGF, the remaining capacity is assumed unused as part of this replacement request. Should the Interconnection Customer choose to proceed with this replacement, the remaining unused capacity would be subject to a separate replacement request such that the total replacement capacity does not exceed this amount and other requirements from SPP tariff Attachment V section 3.9 are met.

RELIABILITY ASSESSMENT STUDY

The Reliability Assessment Study, for the time period between the date that the EGF ceases commercial operations and the Commercial Operation Date of the RGF, evaluates the performance of the Transmission System.

This study compares the conditions on the Transmission System that would exist if the EGF is taken offline to the conditions on the Transmission System as they exist when the EGF is online. The EGF would be responsible for mitigating any reliability violation identified in the study and may not cease operations until all mitigations are implemented or are in service.

Because the EGF was considered retired prior to the Generating Facility Replacement, the performance of the Transmission System with the EGF ceasing commercial operations is the status quo. SPP determined that for the Reliability Assessment Study, no further analysis for the time between removing from service of the EGF and the commission of the RGF is necessary, and no mitigations are applicable.

REPLACEMENT IMPACT STUDY

Aneden was retained by SPP to perform the Replacement Impact Study (Impact Study) for GEN-2023-GR2.

EXISTING VS. REPLACEMENT COMPARISON

To determine which analyses are required for the Impact Study, the differences between the existing configuration and the requested replacement were evaluated. SPP performed this comparison and the resulting analyses using a set of modified study models developed based on the replacement request data and the DISIS-2018-002/2019-001 study models.

STABILITY MODEL PARAMETERS COMPARISION

Because the dynamic model for the EGF and RGF are different (GENROU [EGF] and GENTPJU1 [RGF]), SPP determined short-circuit and dynamic stability analyses were required. This is because the short-circuit contribution and stability responses of the existing configuration and the requested replacement's configuration may differ. The generator dynamic model for the RGF can be found in Appendix A.

As short-circuit and dynamic stability analyses were required, a stability model parameters comparison was not needed for the determination of the scope of the study.

EQUIVALENT IMPEDANCE COMPARISON CALCULATION

As the stability model change determined that short circuit and dynamic stability analyses were required, an equivalent impedance comparison was not needed for the determination of the scope of the study.

SHORT-CIRCUIT ANALYSIS

Aneden performed a short circuit study using the 25SP model to determine the maximum fault current requiring interruption by protective equipment with the RGF online for each bus in the relevant subsystem, and the amount of increase in maximum fault current due to the addition of the RGF. 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 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 GEN-2023-GR2 RGF online.

SPP created a short circuit model using the 25SP stability study model by adjusting the GEN-2023-GR2 short-circuit parameters consistent with the replacement data. The adjusted parameters are shown in Table 2 below.

Table 2: GEN-2023-GR2 Short-Circuit Parameters*

Parameter	Value by Generator Bus#	Value by Generator Bus#
	923521	923522
Machine MVA Base	71.18	71.18
R (pu)	0.0053	0.0053
X'' (pu)	0.144	0.144

*pu values based on Machine MVA Base

RESULTS

The results of the short circuit analysis for the 25SP model are summarized in Table 3 and Table 4. The GEN-2023-GR2 POI bus (Tinker Air Force Base 138 kV) fault current magnitude is provided in Table 3 showing a fault current of 15.9 kA with the RGF online. The addition of the RGF increased the POI bus fault current by 1.89 kA. Table 4 shows the maximum fault current magnitudes and fault current increases with the RGF project online.

The maximum fault current calculated within 5 buses of the POI was 47.19 kA for the 25SP model. There were several buses with a maximum three-phase fault current over 40 kA. These buses are highlighted in Appendix B. The maximum contribution to three-phase fault currents due to the addition of the RGF was about 13.5% and 1.89 kA at the 138 kV POI bus.

Table 3: POI Short-Circuit Results

Case	EGF and RGF-OFF Current (kA)	RGF-ON Current (kA)	kA Change	%Change
25SP	14.00	15.90	1.89	13.5%

Table 4: 25SP Short-Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	11.85	0.01	0.1%
138	47.19	1.89	13.5%
345	34.18	0.24	0.9%
Max	**47.19**	**1.89**	**13.5%**

DYNAMIC STABILITY ANALYSIS

Aneden performed a dynamic stability analysis to identify the impact of the GEN-2023-GR2 project. The analysis was performed according to SPP's Disturbance Performance Requirements[1]. The replacement details are described in the Project and Replacement 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 RGF configuration of 2 x BDAX 7-290ERJT 71.176 MVA synchronous gas-fired units (GENTPJU1) with a total assumed dispatch of 86.846/96.162 MW Summer/Winter. This stability analysis was performed using PTI's PSS/E version 34.8.0 software.

The RGF project details were used to create modified stability models for this impact study based on the DISIS-2018-002/2019-001 stability study models:

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

The dynamic model data for the GEN-2023-GR2 project is provided in Appendix A. The modified power flow models and associated dynamics database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data.

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

- The frequency protective relays at buses 763002, 587958, 534033, 587793, and 587773 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 587793, 920001, 920002, 920003, 920004, 520522, and 516022 were disabled to avoid generator tripping due to an instantaneous over voltage spike after fault clearing.
- Multiple WTDTA1 models were disabled at buses 534023, 532957, 579483, 579486, 760003, 760006, 532712, 532713, 532714, 532715, 539845, 539846, 539847, 539848,

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

539852, 539853, 543654, 588363, 588983, 588984, 589203, 589204, 589243, 760581, 760584, 760749, and 760752 to resolve stability simulation crashes.
- The fault simulation file acceleration factor was reduced, and the iteration limit was increased 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[2]. In addition, voltages of five (5) buses away from the POI of the RGF were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 327 (EES-EAI), 330 (AECI), 351 (EES), 356 (AMMO), 502 (CLEC), 515 (SWPA), 520 (AEPW), 523 (GRDA), 524 (OKGE), 525 (WFEC), 526 (SPS), 527 (OMPA), 534 (SUNC), 536 (WERE), 544 (EMDE), and 546 (SPRM) were monitored. The voltages of all 100 kV and above buses within the study area were monitored as well.

FAULT DEFINITIONS

Aneden developed fault events as required to study the RGF. 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. These contingencies were applied to the modified 25SP and 25WP models.

Table 5: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT9001-3PH	P1	3 phase fault on the TINKER54 (514994) to BARNES 4 (515003) 138 kV line CKT 1, near TINKER54. a. Apply fault at the TINKER54 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
FLT9002-3PH	P1	3 phase fault on the TINKER54 (514994) to TINKER64 (515806) 138 kV line CKT 1, near TINKER54. a. Apply fault at the TINKER54 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
FLT9003-3PH	P1	3 phase fault on the TINKER64 (515806) to TINKER74 (515959) 138 kV line CKT 1, near TINKER64. a. Apply fault at the TINKER64 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
FLT9004-3PH	P1	3 phase fault on the GLENDAL4 (514986) to TINKER74 (515959) 138 kV line CKT 1, near GLENDAL4. a. Apply fault at the GLENDAL4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 10 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on the BARNES 4 (515003) to DRAPER 4 (514933) 138 kV line CKT 1, near BARNES 4. a. Apply fault at the BARNES 4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
FLT9006-3PH	P1	3 phase fault on the BARNES 4 (515003) to SE15TH 4 (514993) 138 kV line CKT 1, near BARNES 4. a. Apply fault at the BARNES 4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line.

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

Table 5 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9007-3PH	P1	3 phase fault on the SE15TH 4 (514993) to GLENDAL4 (514986) 138 kV line CKT 1, near SE15TH 4. a. Apply fault at the SE15TH 4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 10 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.
FLT9008-3PH	P1	3 phase fault on the DRAPER 4 (514933) to SOONRTP4 (514949) 138 kV line CKT 1, near DRAPER 4. a. Apply fault at the DRAPER 4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 10 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	P1	3 phase fault on the DRAPER 4 (514933) to MIDWEST4 (514946) 138 kV line CKT 1, near DRAPER 4. a. Apply fault at the DRAPER 4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 10 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9010-3PH	P1	3 phase fault on the DRAPER 4 (514933) to GM 4 (514961) 138 kV line CKT 1, near DRAPER 4. a. Apply fault at the DRAPER 4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 10 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.
FLT9011-3PH	P1	3 phase fault on the DRAPER2 138 kV (514933) /345 kV (514934) /13.8 kV (515792) XFMR CKT 1, near DRAPER 4 138 kV. a. Apply fault at the DRAPER 4 138 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9012-3PH	P1	3 phase fault on the SE15TH 4 (514993) to HSL 4 (514941) 138 kV line CKT 1, near SE15TH 4. a. Apply fault at the SE15TH 4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 10 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.
FLT9013-3PH	P1	3 phase fault on the HSL 4 (514941) to DUNJEE 4 (514884) 138 kV line CKT 1, near HSL 4. a. Apply fault at the HSL 4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 10 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.
FLT9014-3PH	P1	3 phase fault on the HSL 4 (514941) to JNSKAMO4 (514906) 138 kV line CKT 1, near HSL 4. a. Apply fault at the HSL 4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 10 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.
FLT9015-3PH	P1	3 phase fault on the HSL 4 (514941) to HAMMTAP4 (515046) 138 kV line CKT 1, near HSL 4. a. Apply fault at the HSL 4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 10 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.
FLT9016-3PH	P1	3 phase fault on the HSL 4 (514941) to JONESSB4 (515480) 138 kV line CKT 1, near HSL 4. a. Apply fault at the HSL 4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 10 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.
FLT9017-3PH	P1	3 phase fault on the HSL 4 (514941) to DALE 4 (514987) 138 kV line CKT 1, near HSL 4. a. Apply fault at the HSL 4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 10 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.
FLT9018-3PH	P1	3 phase fault on the HSL1 138 kV (514941) /69 kV (514937) /13.8 kV (515731) XFMR CKT 1, near HSL 4 138 kV. a. Apply fault at the HSL 4 138 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

Table 5 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9019-3PH	P1	3 phase fault on the HSL 138 kV (514941) /13.8 kV (514939) XFMR CKT 1, near HSL 4 138 kV. a. Apply fault at the HSL 4 138 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer. Trip the generator on bus HSL 8G (514939)
FLT9020-3PH	P1	3 phase fault on the HSL 4 (514941) to MIDWAY 4 (514966) 138 kV line CKT 1, near HSL 4. a. Apply fault at the HSL 4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 10 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 MIDWAY 4 (514966) to NE10TH 4 (514964) 138 kV line CKT 1, near MIDWAY 4. a. Apply fault at the MIDWAY 4 138 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 10 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.
FLT9022-3PH	P1	3 phase fault on the DRAPER 7 (514934) to NSUB345 (555234) 345 kV line CKT 1, near DRAPER 7. a. Apply fault at the DRAPER 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.
FLT9023-3PH	P1	3 phase fault on the DRAPER 7 (514934) to SEMINOL7 (515045) 345 kV line CKT 1, near DRAPER 7. a. Apply fault at the DRAPER 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 DRAPER 7 (514934) 345 kV bus** a. Apply single phase fault at DRAPER 7 bus. b. Clear fault after 28 cycles and trip the following elements c. Trip DRAPER 7 (514934) to SEMINOL7 (515045) 345 kV line CKT 2. d. Trip DRAPER2 138 kV (514933) /345 kV (514934) /13.8 kV (515792) XFMR CKT 1.
FLT1002-SB	P4	**Stuck Breaker at DRAPER 7 (514934) 345 kV bus** a. Apply single phase fault at DRAPER 7 bus. b. Clear fault after 28 cycles and trip the following elements c. Trip DRAPER 7 (514934) to SEMINOL7 (515045) 345 kV line CKT 3. d. Trip DRAPER2 138 kV (514933) /345 kV (514934) /13.8 kV (515721) XFMR CKT 1.
FLT1003-SB	P4	**Stuck Breaker at DRAPER 7 (514934) 345 kV bus** a. Apply single phase fault at DRAPER 7 bus. b. Clear fault after 28 cycles and trip the following elements c. Trip DRAPER 7 (514934) to NSUB345 (555234) 345 kV line CKT 1. d. Trip DRAPER2 138 kV (514933) /345 kV (514934) /13.8 kV (515720) XFMR CKT 1.
FLT1004-SB	P4	**Stuck Breaker at DRAPER 4 (514933) 138 kV bus** a. Apply single phase fault at DRAPER 4 bus. b. Clear fault after 28 cycles and trip the following elements c. Trip DRAPER 4 (514933) to SOONRTP4 (514949) 138 kV line CKT 1. d. Trip DRAPER 4 (514933) to MIDWEST4 (514946) 138 kV line CKT 1.
FLT1005-SB	P4	**Stuck Breaker at DRAPER 4 (514933) 138 kV bus** a. Apply single phase fault at DRAPER 4 bus. b. Clear fault after 28 cycles and trip the following elements c. Trip DRAPER 4 (514933) to BARNES 4 (515003) 138 kV line CKT 1. d. Trip DRAPER2 138 kV (514933) /345 kV (514934) /13.8 kV (515721) XFMR CKT 1.
FLT1006-SB	P4	**Stuck Breaker at DRAPER 4 (514933) 138 kV bus** a. Apply single phase fault at DRAPER 4 bus. b. Clear fault after 28 cycles and trip the following elements c. Trip DRAPER 4 (514933) to GM 4 (514961) 138 kV line CKT 1. d. Trip DRAPER2 138 kV (514933) /345 kV (514934) /13.8 kV (515720) XFMR CKT 1.

RESULTS

Table 6 shows the relevant results of the fault events simulated for each of the modified cases. Existing DISIS base case issues are documented separately in Appendix C. The associated stability plots are also provided in Appendix C.

Table 6: Stability Analysis Results

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
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 dynamic stability analysis showed several existing base case issues that were found in both the original DISIS-2018-002/2019-001 model and the model with GEN-2023-GR2 included. These issues were not attributed to the GEN-2023-GR2 replacement request and are detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2023-GR2 replacement request observed during the simulated faults.

INSTALLED CAPACITY EXCEEDS GIA CAPACITY

Under FERC Order 845, Interconnection Customers are allowed to request Interconnection Service that is lower than the full generating capacity of their planned generating facilities. The Interconnection Customers must install acceptable control and protection devices that prevent the injection above their requested Interconnection Service amount measured at the POI.

NECESSARY INTERCONNECTION FACILITIES

This study identified necessary Interconnection Facilities to accommodate GEN-2023-GR2 as shown in Table 7.

Table 7: Necessary Interconnection Facilities

Upgrade Name	Upgrade Description
Tinker Air Force Base 138 kV GEN-2023-GR2 Interconnection (TOIF) (OG&E)	Interconnection upgrades and cost estimates needed to interconnect the following Interconnection Customer facility, GEN-2023-GR2, into the POI at Tinker Air Force Base 138 kV.
Tinker Air Force Base 138 kV GEN-2023-GR2 Interconnection (Non-Shared NU) (OG&E)	Interconnection upgrades and cost estimates needed to interconnect the following Interconnection Customer facility, GEN-2023-GR2, into the POI at Tinker Air Force Base 138 kV.

Should the Interconnection Customer choose to move forward with this request, an Interconnection Facilities Study will be necessary to determine the full scope, cost, and time required to interconnect these upgrades. SPP will work with the TO(s) indicated for the Interconnection Facilities Study.

RESULTS

RELIABILITY ASSESSMENT STUDY

Because the EGF was considered retired prior to the Generating Facility Replacement, the performance of the Transmission System with the EGF ceasing commercial operations is the status quo. SPP determined that for the Reliability Assessment Study, no further analysis for the time between removing from service of the EGF and the commission of the RGF is necessary, and no mitigations are applicable.

REPLACEMENT IMPACT STUDY

In accordance with SPP tariff Attachment V, any material adverse impact from operating the RGF when compared to the EGF would be identified as a Material Modification. In the case that the Interconnection Customer chooses to move forward with the RGF, it must submit the RGF as a new Interconnection Request.

Because no material adverse impacts to the SPP Transmission System were identified, SPP determined the requested replacement is **not a Material Modification**. SPP determined that the requested replacement did not cause a materially adverse impact to the dynamic stability and short-circuit characteristics of the SPP system.

This determination implies that no new upgrades beyond those required for interconnection of the RGF are required, thus not resulting in a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.

NEXT STEPS

As the requested replacement is determined to not be a Material Modification, pursuant to SPP tariff Attachment V section 3.9.3, the Interconnection Customer shall inform SPP within 30 Calendar Days after having received these study results of its election to proceed.

If the Interconnection Customer chooses to proceed with the studied replacement, SPP will initiate an Interconnection Facilities Study and subsequently tender a draft GIA. The Interconnection Customer shall withdraw any associated Attachment AB retirement requests of the EGF, if applicable, and complete the Attachment AE requirements for de-registration of the EGF and registration of the RGF, including transfer or termination of applicable existing transmission service. If the Interconnection Customer would like to obtain new deliverability to final customers, a separate request for transmission service must be requested on SPP’s OASIS.

Failure by the Interconnection Customer to provide an election to proceed within 30 Calendar Days will result in withdrawal of the Interconnection Request pursuant to section 3.7 of SPP tariff Attachment V.