GEN-2016-071

MODIFICATION REQUEST IMPACT STUDY

By SPP Generator Interconnection

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REVISION HISTORY

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EXECUTIVE SUMMARY

Southwest Power Pool performed a Modification Request Impact Study (Study) for GEN-2016-071, an active Generation Interconnection Request (GIR) with a Point of Interconnection (POI) at the Middleton 138kV Tap.

The GEN-2016-071 project interconnects in the Oklahoma Gas and Electric (OKGE) control area with a capacity of 169.2 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2016-071 to change the turbine configuration to 17 x Sierra 3.8 MW Inverters for a total capacity of 64.6 MW. The Inverters are rated at 3.8 MW and do not exceed the GIA amount of 169.2 MW. The generating capacity for GEN-2016-071 (64.6 MW) and the total capability (64.6 MW) fall below its Generator Interconnection Agreement (GIA) Interconnection Service amount, 169.2 MW, as listed in Appendix A of the GIA. In addition, the modification request included changes to the collection system, generator step-up transformer, generation interconnection line, main substation transformer, and reactive power devices. The existing and modified configurations for GEN-2016-071 are shown in Table ES-2.

Table ES-1: GEN-2016-071 Existing Configuration

REQUEST	POINT OF INTERCONNECTION	EXISTING GENERATOR CONFIGURATION	GIA CAPACITY (MW)
GEN-2016-071	Middleton Tap 138kV (514804)	60 x GE 2.82 MW Inverters	169.2 MW

Table ES-2: GEN-2016-071 Modification Request

FACILITY	EXISTING GENERATING FACILITY CONFIGURATION	MODIFICATION GENERATING FACILITY CONFIGURATION
Point of Interconnection	Middleton Tap 138 kV Substation (514804)	Middleton Tap 138 kV Substation (514804)
Configuration/Capacity	60 x GE 2.82 MW Inverters = 169.2 MW	17 x Sierra 3.8 MW Inverters = 64.6 MW
Generation Interconnection Line	Length = 3.25 miles	Length = 2.1 miles
	R = 0.002379 pu	R = 0.001908 pu
	X = 0.011948 pu	X = 0.007829 pu
	B = 0.003768 pu	B = 0.002368 pu
Main Substation Transformer[1]	R = 0.00249 pu	R = 0.00266552 pu
	X = 0.07996 pu	X = 0.0799556 pu
	Winding MVA = 135 MVA	Winding MVA = 72 MVA
	Rating MVA = 225 MVA	Rating MVA = 120 MVA
Equivalent Collector Line[2]	R = 0.00.00525 pu	R = 0.025840 pu
	X = 0.006821 pu	X = 0.0242 pu
	B = 0.080550 pu	B = 0.01712 pu
GSU Transformer[1]	Gen Equivalent Qty: 60	Gen Equivalent Qty: 17
	R = 0.00572 pu	R = 0.0077613 pu
	X = 0.05722 pu	X = 0.077613 pu
	Winding MVA = 195 MVA	Winding MVA = 71.773.8 MW
	Rating MVA = 195 MVA	Rating MVA = 71.773.8 MW
Generator Dynamic Model[3] & Power Factor	REGCA1 Leading and Lagging = ±0.95	REGCA1 Leading and Lagging = ±0.95
Reactive Power Devices	N/A	N/A
1) X/R based on Winding MVA, 2) All pu are on 100 MVA Base 3) DYR stability model name		

SPP determined that powerflow should not be performed because the technology type of the request was unchanged with the modification. However, SPP determined that the change in turbine models necessitated both short-circuit and stability analysis.

SPP performed the analyses using the modification request data based on the DISIS-2021-001 study models:

1. 2025 Summer Peak (25SP),

2. 2025 Winter Peak (25WP)

All analyses were performed using the Siemens PTI PSS/E[1] version 34 software and the results are summarized below.

The short circuit analysis was performed using the 25SP stability model modified for short circuit analysis. The results from the short circuit analysis with the updated topology showed that the maximum GEN-2016-071 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2016-071 POI was no greater than 1.106 kA.

All three-phase fault current levels within 5 buses of the POI with the GEN-2016-071 generator online were below 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. Thirty-two events were simulated, which included three-phase faults and single-line-to-ground stuck breaker faults.

The results of the dynamic stability analysis showed that there were several existing base case issues found in the original DISIS-2021-001 case and the case with the GEN-2016-071 modification. These issues were not attributed to the GEN-2016-071 modification request and detailed in Appendix D.

There were no damping or voltage recovery violations attributed to the GEN-2016-071 modification 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 requested modification has been determined by SPP to **not be a Material Modification**. The requested modification does not have a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date. As the requested modification places the generating capacity of the Interconnection Request at a higher amount than its Interconnection Service, the customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

In accordance with FERC Order No. 827, the generating facility will be required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation.

It is likely that the customer may be required to reduce its generation output to 0 MW in real-time, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

[1] Power System Simulator for Engineering

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) performed a Modification Request Impact Study (Study) for GEN-2016-071. A Modification Request Impact Study is a generation interconnection study performed to evaluate the impacts of modifying the DISIS study assumptions. The determination of the required scope of the study is dependent upon the specific modification requested and how it may impact the results of the DISIS study. Impacting the DISIS results could potentially affect the cost or timing of any Interconnection Request with a later Queue priority date, deeming the requested modification a Material Modification. The criteria sections below include reasoning as to why an analysis was either included or excluded from the scope of study.

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

STEADY-STATE ANALYSIS

SPP determined that powerflow should not be performed because the technology type of the request was unchanged with the modification.

STABILITY ANALYSIS, SHORT-CIRCUIT ANALYSIS

To determine whether stability and short circuit analyses are required, SPP evaluates the difference between the stability model parameters and, if needed, the equivalent collector system impedance between the existing configuration and the requested modification. Dynamic stability analysis and short circuit analysis would be required if the differences listed above were determined to have a significant impact on the most recently performed DISIS stability analysis.

REACTIVE POWER ANALYSIS

SPP requires that a charging current compensation analysis be performed on the requested modification configuration as it is a non-synchronous resource. The charging current compensation analysis determines the capacitive effect at the POI caused by the project's collector system and transmission line's capacitance. A shunt reactor size is determined in order to offset the capacitive effect and maintain zero (0) MVAr flow at the POI while the project's generators and capacitors are offline.

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.

PROJECT AND MODIFICATION REQUEST

The GEN-2016-071 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a Point of Interconnection (POI) at the Middleton 138kV Tap. At the time of report posting, GEN-2016-071 is an active Interconnection Request with a queue status of "IA FULLY EXECUTED/ON SCHEDULE." GEN-2016-071 is a solar plant with a maximum summer and winter queue capacity of 169.2 MW with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).

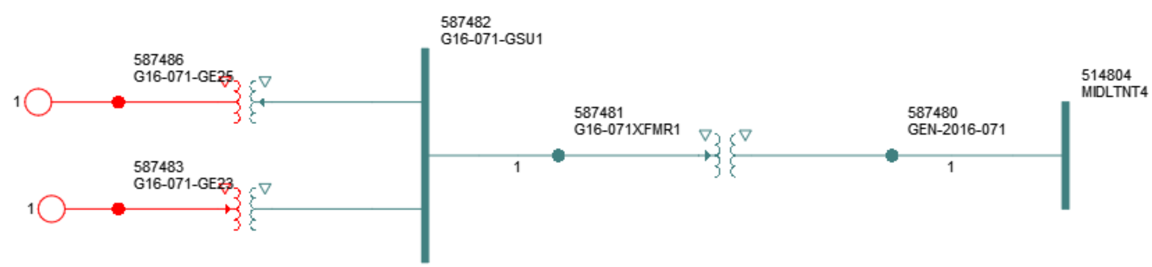
The GEN-2016-071 project is currently in the DISIS-2017-001 cluster.

Figure 0-1 shows the powerflow model single line diagram for the existing GEN-2016-071 configuration using the DISIS-2021-001 stability models. The GEN-2016-071 project interconnects in the Oklahoma Gas and Electric (OKGE) control area with a capacity of 169.2 MW as shown in Table 0-1 below.

Table 0-1: GEN-2016-071 Existing Configuration

REQUEST	POINT OF INTERCONNECTION	EXISTING GENERATOR CONFIGURATION	GIA CAPACITY (MW)
GEN-2016-071	Middleton 138kV (514804)	60 x GE 2.82 MW Inverters	169.2 MW

Figure 0-1: GEN-2016-071 Single Line Diagram (Existing Configuration*)



*based on the DISIS-2021-001 stability models

This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2016-071 to an turbine configuration of 17 x Sierra 3.8 MW Inverters MVA Inverters 3.8 MW for a total capacity of 64.6 MW. This generating capacity for GEN-2016-071 (64.6 MW) and the total capability (64.6 MW) exceed its Generator Interconnection Agreement (GIA) Interconnection Service amount, 169.2 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

In addition, the modification request included changes to the collection system, generator step-up transformer, generation interconnection line, main substation transformer, and reactive power devices. Figure 0-2 shows the powerflow model single line diagram for the GEN-2016-071 modification. The existing and modified configurations for GEN-2016-071 are shown in

Table 0-2.

Figure 0-2: GEN-2016-071 Single Line Diagram (Modification Configuration)

Table 0-2: GEN-2016-071 Modification Request

FACILITY	EXISTING GENERATING FACILITY CONFIGURATION	MODIFICATION GENERATING FACILITY CONFIGURATION
Point of Interconnection	Middleton Tap 138 kV Substation (514804)	Middleton Tap 138 kV Substation (514804)
Configuration/Capacity	60 x GE 2.82 MW Inverters = 169.2 MW	17 x Sierra 3.8 MW Inverters = 64.6 MW
Generation Interconnection Line	Length = 3.25 miles	Length = 2.1 miles
	R = 0.002379 pu	R = 0.001908 pu
	X = 0.011948 pu	X = 0.007829 pu
	B = 0.003768 pu	B = 0.002368 pu
Main Substation Transformer[1]	R = 0.00249 pu	R = 0.00266552 pu
	X = 0.07996 pu	X = 0.0799556 pu
	Winding MVA = 135 MVA	Winding MVA = 72 MVA
	Rating MVA = 225 MVA	Rating MVA = 120 MVA
Equivalent Collector Line[2]	R = 0.00.00525 pu	R = 0.025840 pu
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GSU Transformer[1]	Gen Equivalent Qty: 60	Gen Equivalent Qty: 17
	R = 0.00572 pu	R = 0.0077613 pu
	X = 0.05722 pu	X = 0.077613 pu
	Winding MVA = 195 MVA	Winding MVA = 71.773.8 MW
	Rating MVA = 195 MVA	Rating MVA = 71.773.8 MW
Generator Dynamic Model[3] & Power Factor	REGCA1 Leading and Lagging = ±0.95	REGCA1 Leading and Lagging = ±0.95
Reactive Power Devices	N/A	N/A
1) X/R based on Winding MVA, 2) All pu are on 100 MVA Base 3) DYR stability model name		

EXISTING VERSUS MODIFICATION COMPARISON

To determine which analyses are required for the Study, the differences between the existing configuration and the requested modification were evaluated. SPP performed this comparison and the resulting analyses using a set of modified study models developed based on the modification request data and the DISIS-2021-001 study models.

The methodology and results of the comparisons are described below. The analysis was completed using PSS/E version 34 software.

STABILITY MODEL PARAMETERS COMPARISON

SPP determined that short circuit and dynamic stability analyses were required because of the turbine change from General Electric to Power Electronic. This is because the short circuit contribution and stability responses of the existing configuration and the requested modification's configuration may differ. The generator dynamic model for the modification can be found in Appendix A.

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

EQUIVALENT IMPEDANCE COMPARISON CALCULATION

As the turbine 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

A short circuit study was performed using the 25SP model for GEN-2016-071. 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 GEN-2016-071 online.

SPP created a short circuit model using the 25SP DISIS-2021-001 stability study model by adjusting the GEN-2016-071 short circuit parameters consistent with the modification data. The adjusted parameters are shown in Table 0-1 below.

Table 0-1: Short Circuit Model Parameters*

PARAMETER	VALUE BY GENERATOR BUS#
	514804
Machine MVA Base	33.6
R (pu)	0.0
X'' (pu)	0.893

*pu values based on Machine MVA Base

RESULTS

The results of the short circuit analysis for the 25SP model are summarized in ase fault current was about 13.43% and 1.106 kA.

Table 0-1 and

Table 0-2. The GEN-2016-071 POI bus (Middleton 138kV - 514804) fault current magnitudes are provided in ase fault current was about 13.43% and 1.106 kA.

Table 0-1 showing a maximum fault current of 6.66 kA with the GEN-2016-071 project online.

Table 0-2 shows the maximum fault current magnitudes and fault current increases with the GEN-2016-071 project online.

The maximum fault current calculated within five buses of the GEN-2016-071 POI (including the POI bus) was less than 40 kA for the 25SP model.

The maximum GEN-2016-071 contribution to three-phase fault current was about 13.43% and 1.106 kA.

Table 0-1: POI Short Circuit Results

CASE	GEN-OFF CURRENT (KA)	GEN-ON CURRENT (KA)	MAX KA CHANGE	MAX %CHANGE
25SP	8.233	9.339	1.106	13.43%

Table 0-2: 25SP Short Circuit Results

VOLTAGE (KV)	MAX. CURRENT (KA)	MAX KA CHANGE	MAX %CHANGE
69	14.039	0.483	3.56%
138	23.567	0.054	0.23%
345	13.252	0.026	0.2%
Max	**23.567**	**0.483**	**3.56%**

DYNAMIC STABILITY ANALYSIS

SPP performed a dynamic stability analysis to identify the impact of the turbine configuration change and other modifications to GEN-2016-071. The analysis was performed according to SPP's Disturbance Performance Requirements[2]. The modification details are described in the Project and Modification 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 D.

METHODOLOGY AND CRITERIA

The dynamic stability analysis was performed using models developed with the requested GEN-2016-071 configuration of 17 x Sierra 3.8 MW Inverters MVA Inverters (REGCA1). This stability analysis was performed using PTI's PSS/E version 34.8.0 software.

The modifications requested for the GEN-2016-071 project were used to create modified stability models for this impact study based on the DISIS-2021-001 stability study models:

1. 2025 Summer Peak (25SP),
2. 2025 Winter Peak (25WP)

The modified dynamic model data for the GEN-2016-071 project is provided in Appendix A. The modified powerflow 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.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2016-071 and other current and prior queued projects in their cluster group[3]. In addition, voltages of five (5) buses away from the POI of GEN-2016-071 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 536, 330, 520, 524, 531, 534, 541, 542, 544, 545, 546, 640, and 645 were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

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

[3] Based on the DISIS-2021-001 Cluster Groups

FAULT DEFINITIONS

SPP developed and simulated faults for GEN-2017-121 using the modified study models. The new set of faults were 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 0-1 below. These contingencies were applied to the modified 25SP and 25WP models.

Table 0-1: Fault Definitions

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT9002-3PH	P1	3 phase fault on the CHILOCCO4 (521198) to MIDLTNT4 (514804) 138 kV line CKT 1, near CHILOCCO4. a. Apply fault at the CHILOCCO4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 7 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 20 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1	3 phase fault on the MIDLTNT4 (514804) to PECKHMT4 (515381) 138 kV line CKT 1, near MIDLTNT4. a. Apply fault at the MIDLTNT4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9004-3PH	P1	3 phase fault on the MIDLTNT4 (514804) to PECKHMT4 (515381) 138 kV line CKT 1, near MIDLTNT4. a. Apply fault at the MIDLTNT4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on the NWBRAMN4 (520450) to PECKHMT4 (515381) 138 kV line CKT 1, near NWBRAMN4. a. Apply fault at the NWBRAMN4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 7 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 20 cycles, then trip the line in (b) and remove fault.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT9006-3PH	P1	3 phase fault on the PECKHMT4 (515381) to NEWKIRK4 (514759) 138 kV line CKT 1, near PECKHMT4. a. Apply fault at the PECKHMT4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9007-3PH	P1	3 phase fault on the OMNUKRK4 (529290) to NEWKIRK4 (514759) 138 kV line CKT 1, near OMNUKRK4. a. Apply fault at the OMNUKRK4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 7 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 20 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 phase fault on the NEWKIRK4 (514759) to NWKRKAT4 (514764) 138 kV line CKT 1, near NEWKIRK4. a. Apply fault at the NEWKIRK4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	P1	3 phase fault on the NEWKIR-WFEC4 (521012) to NWKRKAT4 (514764) 138 kV line CKT 1, near NEWKIR-WFEC4. a. Apply fault at the NEWKIR-WFEC4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 7 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 20 cycles, then trip the line in (b) and remove fault.
FLT9010-3PH	P1	3 phase fault on the NWKRKAT4 (514764) to KILDARE4 (514760) 138 kV line CKT 1, near NWKRKAT4. a. Apply fault at the NWKRKAT4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9011-3PH	P1	3 phase fault on the KILDARE4 (514760) to WHEAGLE4 (514761) 138 kV line CKT 1, near KILDARE4. a. Apply fault at the KILDARE4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT9012-3PH	P1	3 phase fault on the KILDARE4 (514760) to CHIKASI4 (514757) 138 kV line CKT 1, near KILDARE4. a. Apply fault at the KILDARE4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9014-3PH	P1	3 phase fault on the CRESWLN4 138kV (532981)/ 69 kV (533543)/ 13.2 kV (533080) XFMR CKT 1, near CRESWLN4 138 kV. a. Apply fault at the CRESWLN4 138 kV bus. b. Clear fault after 7 cycles and trip the faulted XFMR.
FLT9018-3PH	P1	3 phase fault on the CRESWLN4 138kV (532981)/ 69 kV (533573)/ 13.2 kV (533081) XFMR CKT 1, near CRESWLN4 138 kV. a. Apply fault at the CRESWLN4 138 kV bus. b. Clear fault after 7 cycles and trip the faulted XFMR.
FLT9019-3PH	P1	3 phase fault on the SLATECRK4 (533070) to CRESWLN4 (532981) 138 kV line CKT 1, near SLATECRK4. a. Apply fault at the SLATECRK4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 7 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 20 cycles, then trip the line in (b) and remove fault.
FLT9020-3PH	P1	3 phase fault on the CRESWLN4 (532981) to OXFORD 4 (532982) 138 kV line CKT 1, near CRESWLN4. a. Apply fault at the CRESWLN4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9021-3PH	P1	3 phase fault on the CRESWLN2 (533543) to CRESWLS2 (533573) 138 kV line CKT Z1, near CRESWLN2. a. Apply fault at the CRESWLN2 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9022-3PH	P1	3 phase fault on the CRESWLS2 (533548) to CRESWLS2 (533573) 69 kV line CKT 1, near CRESWLS2. a. Apply fault at the CRESWLS2 69 kV bus. b. Clear fault after 7 cycles by tripping the faulted line.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		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.
FLT9025-3PH	P1	3 phase fault on the OXFORD4 (532982) to SUMNER 4 (532984) 138 kV line CKT 1, near OXFORD4. a. Apply fault at the OXFORD4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9026-3PH	P1	3 phase fault on the SUMNER4 (532984) to TIMBJCT4 (532992) 138 kV line CKT 1, near SUMNER4. a. Apply fault at the SUMNER4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9028-3PH	P1	3 phase fault on the VIOLA4 (533075) to SUMNER 4 (532984) 138 kV line CKT 1, near VIOLA4. a. Apply fault at the VIOLA4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9029-3PH	P1	3 phase fault on the GEN-2017-121 (761838) to SUMNER 4 (532984) 138 kV line CKT 1, near GEN-2017-121. a. Apply fault at the GEN-2017-121 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9030-3PH	P1	3 phase fault on the SC10BEL4 (533063) to SUMNER 4 (532984) 138 kV line CKT 1, near SC10BEL4. a. Apply fault at the SC10BEL4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9031-3PH	P1	3 phase fault on the FARBER4 (533042) to SC10BEL4 (533063) 138 kV line CKT 1, near FARBER4. a. Apply fault at the FARBER4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		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 MIDLTNT4 on the 138kV bus after 16 cycles a. Trip the MIDLTNT4 to CRESWLN4 Transmission Line Ckt 1 b. Trip the MIDLTNT4 to PECKHMT4 Transmission Line Ckt 1
FLT1002-SLG	P4	Apply single-phase fault at MIDLTNT4 on the 138kV bus after 16 cycles a. Trip the MIDLTNT4 to CHILOCCO4 Transmission Line Ckt 1 b. Trip the MIDLTNT4 to PECKHMT4 Transmission Line Ckt 1
FLT1003-SLG	P4	Apply single-phase fault at MIDLTNT4 on the 138kV bus after 16 cycles a. Trip the MIDLTNT4 to CRESWLN4 Transmission Line Ckt 1 b. Trip the MIDLTNT4 to CHILOCCO4 Transmission Line Ckt 1

RESULTS

Table 0-1 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 D. The associated stability plots are also provided in Appendix D.

Table 0-1: GEN-2016-071 Dynamic Stability Results

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	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
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	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
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	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
FLT1001-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SLG	Pass	Pass	Stable	Pass	Pass	Stable

The results of the dynamic stability analysis showed that there were several existing base case issues found in the original DISIS-2021-001 case and the case with the GEN-2016-071 modification. These issues were not attributed to the GEN-2016-071 modification request and detailed in Appendix D.

There were no damping or voltage recovery violations attributed to the GEN-2016-071 modification 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.

MODIFIED CAPACITY EXCEEDS GIA CAPACITY

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

As such, Interconnection Customers are allowed to increase the generating capacity of a generating facility without increasing its Interconnection Service amount stated in its GIA. This is allowable as long as they install the proper control and protection devices, and the requested modification is not determined to be a Material Modification.

RESULTS

The modified generating capacity of GEN-2016-071 (169.2 MW) and the total capability (64.6 MW) exceed the GIA Interconnection Service amount, 169.2 MW, as listed in Appendix A of the GIA. The GEN-2016-071 Inverters are rated at 3.8 MW, and use a power plant controller (PPC) to limit the total power injected into the POI.

The customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

MATERIAL MODIFICATION DETERMINATION

In accordance with Attachment V of SPP's Open Access Transmission Tariff, for modifications other than those specifically permitted by Attachment V, SPP shall evaluate the proposed modifications prior to making them and inform the Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Material Modification shall mean (1) modification to an Interconnection Request in the queue that has a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date; or (2) planned modification to an Existing Generating Facility that is undergoing evaluation for a Generating Facility Modification or Generating Facility Replacement, and has a material adverse impact on the Transmission System with respect to: i) steady-state thermal or voltage limits, ii) dynamic system stability and response, or iii) short-circuit capability limit; compared to the impacts of the Existing Generating Facility prior to the modification or replacement.

RESULTS

SPP determined the requested modification is **not a Material Modification** based on the results of this Modification Request Impact Study performed by SPP. SPP evaluated the impact of the requested modification on the prior study results. SPP determined that the requested modification did not negatively impact the prior study dynamic stability and short circuit results, and the modifications to the project were not enough to change the previously studied powerflow conclusions.

This determination implies that any network upgrades already required by GEN-2016-071 would not be negatively impacted and that no new upgrades are required due to the requested modification, thus not resulting in a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.