GEN-2017-164/178 & 2024-SR11

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-2017-164/178, an active Generation Interconnection Request (GIR) with a Point of Interconnection (POI) at the Woodring 345kV Substation.

The GEN-2017-164/178 & 2024-SR11 project interconnects in the Oklahoma Gas and Electric (OG&E) control area with a capacity of 302 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2017-164/178 & 2024-SR11 to change the inverter configuration to 69 x PE FS4200 / 21 x PE FP4200 inverters for GEN-2017-164/178 and 59x PE FP4200 Inverters for 2024-SR11 a total capacity of 302 MW. The inverters are rated at 3.691 MW and use a Power Plant Controller (PPC) to limit the total power injected into the POI. The generating capacity for GEN-2017-164/178 (302 MW) and the total capability (302 MW) exceed its Generator Interconnection Agreement (GIA) Interconnection Service amount, 302 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. The existing and modified configurations for GEN-2017-164/178 & 2024-SR11 are shown in Table ES-2.

Table ES-1: GEN-2017-164/178 Modified Configuration

REQUEST	POINT OF INTERCONNECTION	GENERATOR CONFIGURATION	GIA CAPACITY (MW)
GEN-2017-164/178	Woodring 345kV Substation (514715)	69 x PE FS4200 / 21 x PE FP4200 inverters	302 MW
GEN-2024-SR11	Woodring 345kV Substation (514715)	59x PE FP4200 Inverters	200MW

Table ES-2: GEN-2017-164/178 & SR11 Modification Request

Facility	Existing Generating Facility Configuration	Modification Generating Facility Configuration			
Point of Interconnection	Woodring 345 kV Substation (514715)	Woodring 345 kV Substation (514715)			
Configuration/Capacity	139x GE PV .90MW/1.0 MVA up to 250MW 14x TMEIC Ninja 840 3.714/4.05 (BESS) = 52MW Total POI injection for GEN-2017-164/178 = 302 MW	69 x PV PE FS4200 Inverters & 21 x Storage PE FP4200 Inverters = 302 MW			
Generation Interconnection Line	Length = 13 miles	Length = 1 miles			
	R = 0.000637 pu	R = 0.00005 pu			
	X = 0.006487 pu	X = 0.0000480 pu			
	B = 0.109200 pu	B = 0.000887 pu			
Main Substation Transformer	R = .199%	R = .17%	R = .17%	R =.18%	
	X = 7.998%	X = 8.5%	X = 8.35%	X =8.37%	
	Winding MVA = 168 MVA	Winding MVA = 102 MVA	Winding MVA = 52 MVA	Winding MVA = 52 MVA	
	Rating MVA = 280 MVA	Rating MVA = 170 MVA	Rating MVA = 85 MVA	Rating MVA = 85 MVA	
Equivalent collector line	R = 0	R = .00782 pu	R = .0168 pu	R = .00068 pu	R = .00713 pu
	X = 0	X = 0.0116 pu	X = 0.0250 pu	X = 0.00216 pu	X = 0.00834 pu
	B = 0.080550 pu	B = 0.0415 pu	B = 0.0259 pu	B = 0.00163 pu	B = 0.0111 pu
GSU Transformer	Gen Equivalent Qty: 69	Gen Equivalent Qty: 35	Gen Equivalent Qty: 17	Gen Equivalent Qty: 17	Gen Equivalent Qty: 21
	R = 0	R = .87%	R =. 66%	R = .66%	R = .67%
	X = 0	X = 8.96%	X = 6.78%	X = 6.78%	X = 6.88%
	Winding MVA = 231.385 MVA	Winding MVA = 4.2 MVA	Winding MVA = 4.2 MVA	Winding MVA = 4.2 MVA	Winding MVA = 4.2 MVA
	Rating MVA = 231.4 MVA	Rating MVA = 4.2 MVA	Rating MVA = 4.2 MVA	Rating MVA = 4.2 MVA	Rating MVA = 4.2 MVA
Generator Dynamic Model and Power Factor	REGCA1 Leading and Lagging = ±0.866	REGCA1 Leading and Lagging = ±0.879			
Reactive Power Devices	N/A	N/A			

Facility	Existing Generating Facility Configuration	Modification Generating Facility Configuration
Point of Interconnection	Woodring 345 kV Substation (514715)	Woodring 345 kV Substation (514715)

Configuration/Capacity	55 x PE HEM FP4200M 3.63636 MW (BESS) = 199.9998 MW [dispatch] Units are rated at 4.2 MW, PPC to limit GEN-2024-SR11 to 200 MW at the POI and total POI injection w/ GEN-2017-164 to 250 MW	59x PE FP4200 Inverters 3.427/4.207MVA limit to 200 MW	
Generation Interconnection Line	Length = 13 miles		
	R = 0.000637 pu		
	X = 0.006487 pu		
	B = 0.109200 pu		
Main Substation Transformer	R = .199%		
	X = 7.998%		
	Winding MVA = 168 MVA		
	Rating MVA = 280 MVA		
Equivalent collector line	R = 0	R=.0012 pu	R=.00177 pu
	X = 0	X= .00401 pu	X= .005761 pu
	B = 0.080550 pu	B = .01076	B = .00411
GSU Transformer	Gen Equivalent Qty: 55	Gen Equivalent Qty: 38	Gen Equivalent Qty: 21
	R = .94%	R = .87%	R = .66%
	X =5.93%	X = 8.96%	X = 6.78%
	Winding MVA = 231.385 MVA	Winding MVA = 4.2 MVA	Winding MVA = 4.2 MVA
	Rating MVA = 231.4 MVA	Rating MVA = 4.2 MVA	Rating MVA = 4.2 MVA
Generator Dynamic Model and Power Factor	REGCA1 Leading and Lagging = ±0.866	REGCA1 Leading and Lagging = ±0.816	

The scope of this modification request study included charging current compensation analysis, short circuit analysis, and dynamic 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 results of the charging current compensation analysis using the 25SP models showed that the GEN-2017-164/178 &2024-SR11 project needed a 9.9 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place. This is necessary to offset the capacitive

[1] Power System Simulator for Engineering

effect on the transmission network caused by the project's transmission line and collector system during reduced generation conditions. The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The 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-2017-164/178 & 2024-SR11 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2017-164/178 POI showed that there were multiple buses with a maximum three-phase fault current over 40 kA. These buses are highlighted in Appendix B.

The dynamic stability analysis was performed using Siemens PTI PSS/E version 34.8.0 software for the two modified study models: 25SP and 25WP. Fifty-nine 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-2017-164/178 & 2024-SR11 modification. These issues were not attributed to the GEN-2017-164/178 &2024-SR11 modification request and detailed in Appendix D.

There were no damping or voltage recovery violations attributed to the GEN-2017-164/178 & 2024-SR11 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.

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-2017-164/178 & 2024-SR11. 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-2017-164/178 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a Point of Interconnection (POI) at the Woodring 345kV Substation. At the time of report posting, GEN-2017-164/178 is an active Interconnection Request with a queue status of "IA FULLY EXECUTED/ON SCHEDULE." GEN-2017-164/178 is a solar plant with a maximum summer and winter queue capacity of 302 MW with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).

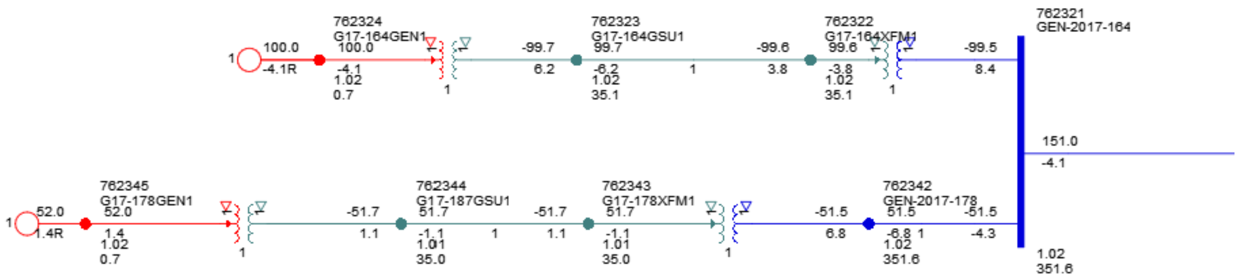
The GEN-2017-164/178 project is currently in the DISIS-2021-001 cluster.

Figure 0-1 shows the powerflow model single line diagram for the existing GEN-2017-164/178 configuration using the DISIS-2021-001 stability models. The GEN-2017-164/178 project interconnects in the Oklahoma Gas and Electric (OG&E) control area with a capacity of 302 MW as shown in Table 0-1 below.

Table 0-1: GEN-2017-164/178 Modified Configuration

REQUEST	POINT OF INTERCONNECTION	GENERATOR CONFIGURATION	GIA CAPACITY (MW)
GEN-2017-164/178	Woodring 345kV (514715)	69 x PE FS4200 / 21 x PE FP4200 inverters	302MW
GEN-2024-SR11	Woodring 345kV Substation (514715)	59x PE FP4200 Inverters	200MW

Figure 0-1: GEN-2017-164/178 Single Line Diagram (Existing Configuration*)



*based on the DISIS-2021-001 stability models

This Study has been requested to evaluate the modification of GEN-2017-164/178 & 2024-SR11 to change the inverter configuration to 69 x PE FS4200 / 21 x PE FP4200 inverters for GEN-2017-164/178 and 59x PE FP4200 Inverters for 2024-SR11 a total capacity of 302 MW. This generating capacity for GEN-2017-164/178 & 2024-SR11 (302 MW) and the total capability (302 MW) exceed its Generator Interconnection Agreement (GIA) Interconnection Service amount, 302 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-2017-164/178 & 2024-SR11 modification. The existing and modified configurations for GEN-2017-164/178 & 2024-SR11 are shown in

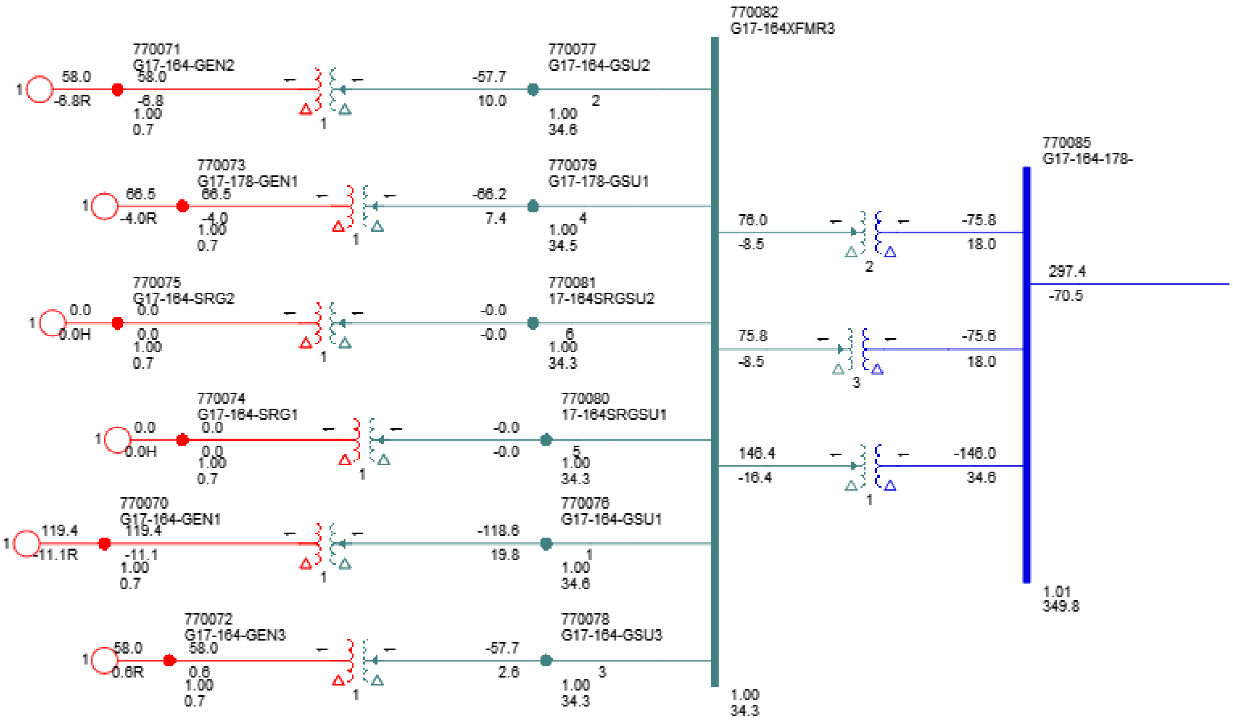


Table 0-2.

Figure 0-2: GEN-2017-164/178 & 2024-SR11 Single Line Diagram (Modification Configuration)

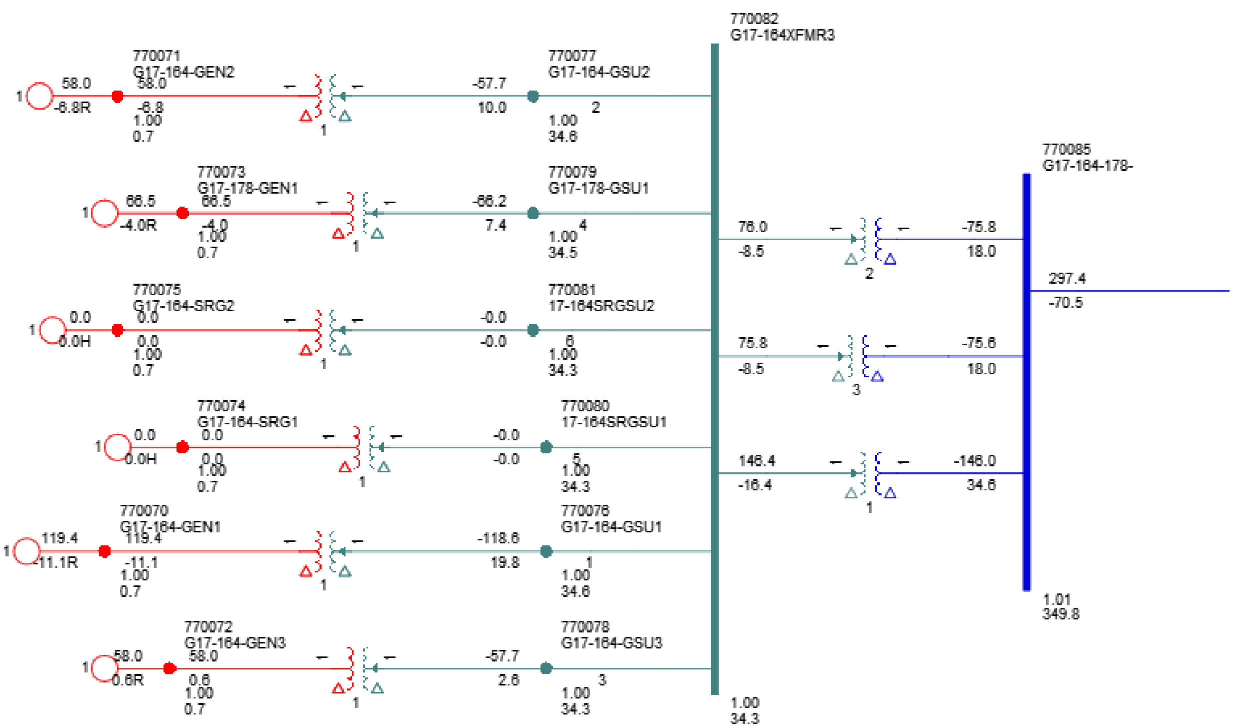


Table 0-2: GEN-2017-164/178 Modification Request

Facility	Existing Generating Facility Configuration	Modification Generating Facility Configuration			
Point of Interconnection	Woodring 345 kV Substation (514715)	Woodring 345 kV Substation (514715)			
Configuration/Capacity	139x GE PV .90MW/1.0 MVA up to 250MW 14x TMEIC Ninja 840 3.714/4.05 (BESS) = 52MW Total POI injection for GEN-2017-164/178 = 302 MW	69 x PV PE FS4200 Inverters & 21 x Storage PE FP4200 Inverters = 302 MW			
Generation Interconnection Line	Length = 13 miles	Length = 1 miles			
	R = 0.000637 pu	R = 0.00005 pu			
	X = 0.006487 pu	X = 0.0000480 pu			
	B = 0.109200 pu	B = 0.000887 pu			
Main Substation Transformer	R = .199%	R = .17%	R = .17%	R =.18%	
	X = 7.998%	X = 8.5%	X = 8.35%	X =8.37%	
	Winding MVA = 168 MVA	Winding MVA = 102 MVA	Winding MVA = 52 MVA	Winding MVA = 52 MVA	
	Rating MVA = 280 MVA	Rating MVA = 170 MVA	Rating MVA = 85 MVA	Rating MVA = 85 MVA	
Equivalent collector line	R = 0	R = .00782 pu	R = .0168 pu	R = .00068 pu	R = .00713 pu
	X = 0	X = 0.0116 pu	X = 0.0250 pu	X = 0.00216 pu	X = 0.00834 pu
	B = 0.080550 pu	B = 0.0415 pu	B = 0.0259 pu	B = 0.00163 pu	B = 0.0111 pu
GSU Transformer	Gen Equivalent Qty: 69	Gen Equivalent Qty: 35	Gen Equivalent Qty: 17	Gen Equivalent Qty: 17	Gen Equivalent Qty: 21
	R = 0	R = .87%	R =. 66%	R = .66%	R = .67%
	X = 0	X = 8.96%	X = 6.78%	X = 6.78%	X = 6.88%
	Winding MVA = 231.385 MVA	Winding MVA = 4.2 MVA	Winding MVA = 4.2 MVA	Winding MVA = 4.2 MVA	Winding MVA = 4.2 MVA
	Rating MVA = 231.4 MVA	Rating MVA = 4.2 MVA	Rating MVA = 4.2 MVA	Rating MVA = 4.2 MVA	Rating MVA = 4.2 MVA
Generator Dynamic Model and Power Factor	REGCA1 Leading and Lagging = ±0.866	REGCA1 Leading and Lagging = ±0.879			
Reactive Power Devices	N/A	N/A			

Facility	Existing Generating Facility Configuration	Modification Generating Facility Configuration
Point of Interconnection	Woodring 345 kV Substation (514715)	Woodring 345 kV Substation (514715)

Configuration/Capacity	55 x PE HEM FP4200M 3.63636 MW (BESS) = 199.9998 MW [dispatch] Units are rated at 4.2 MW, PPC to limit GEN-2024-SR11 to 200 MW at the POI and total POI injection w/ GEN-2017-164 to 250 MW	59x PE FP4200 Inverters 3.427/4.207MVA limit to 200 MW	
Generation Interconnection Line	Length = 13 miles		
	R = 0.000637 pu		
	X = 0.006487 pu		
	B = 0.109200 pu		
Main Substation Transformer	R = .199%		
	X = 7.998%		
	Winding MVA = 168 MVA		
	Rating MVA = 280 MVA		
Equivalent collector line	R = 0	R=.0012 pu	R=.00177 pu
	X = 0	X= .00401 pu	X= .005761 pu
	B = 0.080550 pu	B = .01076	B = .00411
GSU Transformer	Gen Equivalent Qty: 55	Gen Equivalent Qty: 38	Gen Equivalent Qty: 21
	R = .94%	R = .87%	R = .66%
	X =5.93%	X = 8.96%	X = 6.78%
	Winding MVA = 231.385 MVA	Winding MVA = 4.2 MVA	Winding MVA = 4.2 MVA
	Rating MVA = 231.4 MVA	Rating MVA = 4.2 MVA	Rating MVA = 4.2 MVA
Generator Dynamic Model and Power Factor	REGCA1 Leading and Lagging = ±0.866	REGCA1 Leading and Lagging = ±0.816	

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 inverter 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 inverter 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.

CHARGING CURRENT COMPENSATION ANALYSIS

The charging current compensation analysis was performed for GEN-2017-164/178 to determine the capacitive charging effects during reduced generation conditions (unsuitable wind speeds, unsuitable solar irradiance, insufficient state of charge, idle conditions, curtailment, etc.) at the generation site and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

METHODOLOGY AND CRITERIA

The GEN-2017-164/178 & 2024-SR11 generators and capacitors were switched out of service while other system elements remained in-service. A shunt reactor was tested at the project's collection substation 34.5 kV bus to set the MVAr flow into the POI to approximately zero. The size of the shunt reactor is equivalent to the charging current value at unity voltage and the compensation provided is proportional to the voltage effects on the charging current (i.e., for voltages above unity, reactive compensation is greater than the size of the reactor).

SPP performed the charging current compensation analysis using the modification request data based on the 2025 Summer Peak (25SP) DISIS-2021-001 stability study models.

RESULTS

The results from the analysis showed that the GEN-2017-164/178 & 2024-SR11 project needed approximately 9.9 MVAr of compensation at its project substation to reduce the POI MVAr to zro.

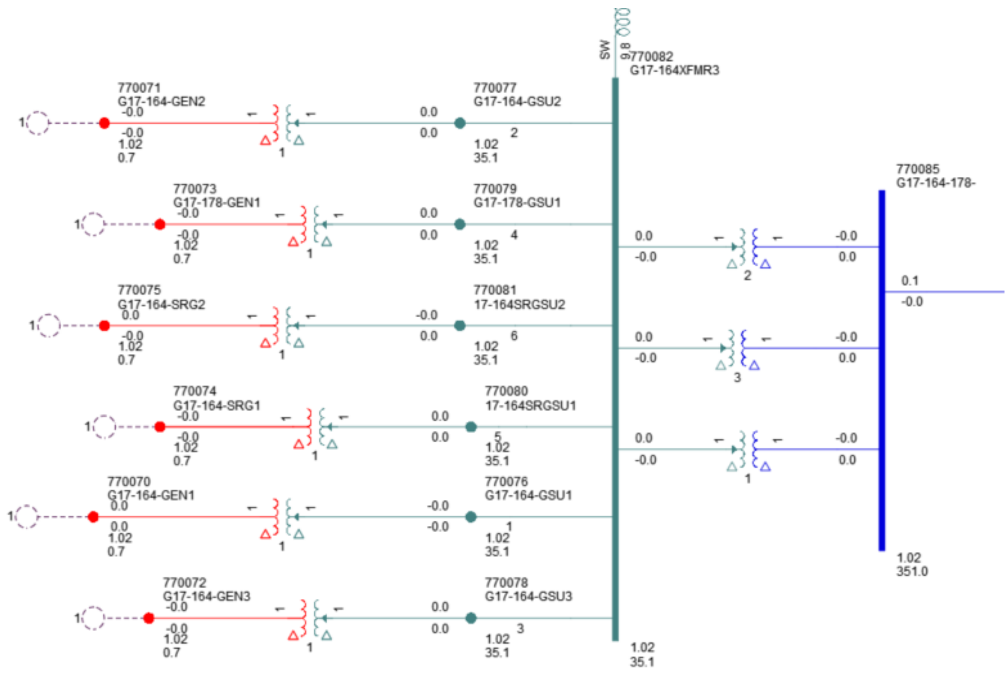
Figure 0-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the updated topology. The final shunt reactor requirements for GEN-2017-164/178 are shown in Table 0-1.

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

Table 0-1: Shunt Reactor Size for Reduced Generation Study (Modification)

MACHINE	POI BUS NUMBER	POI BUS NAME	REACTOR SIZE (MVAR)
			25SP
GEN-2017-164/178 & 2024-SR11	Woodring 345kV (514715)	Woodring 345kV Substation (514715)	9.9Mvar

Figure 0-1: GEN-2017-164/178 &2024-SR11 Single Line Diagram w/ Charging Current Compensation (Modification)



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SHORT CIRCUIT ANALYSIS

A short circuit study was performed using the 25SP model for GEN-2017-164/178 & 2024-SR11. 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 345 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-2017-164/178 & 2024-SR11 online.

SPP created a short circuit model using the 25SP DISIS-2021-001 stability study model by adjusting the GEN-2017-164/178 & 2024-SR11 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#
	514715
Machine MVA Base	4.2
R (pu)	0.0
X'' (pu)	0.879/.816

*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 4.21% and 0.796 kA.

Table 0-1 and

Table 0-2. The GEN-2017-164/178 & 2024-SR11 POI bus (Woodring 345kV - 514715) fault current magnitudes are provided in ase fault current was about 4.21% and 0.796 kA.

Table 0-1 showing a maximum fault current of 6.66 kA with the GEN-2017-164/178 & 2024-SR11 project online.

Table 0-2 shows the maximum fault current magnitudes and fault current increases with the GEN-2017-164/178 & 2024-SR11 project online.

There were several buses with a maximum three-phase fault current over 40 kA. These buses are highlighted in Appendix B.

The maximum GEN-2017-164/178 & 2024-SR11 contribution to three-phase fault current was about 4.21% and 0.796 kA.

Table 0-1: POI Short Circuit Results

CASE	GEN-OFF CURRENT (KA)	GEN-ON CURRENT (KA)	MAX KA CHANGE	MAX %CHANGE
25SP	19.755	18.902	0.853	4.51%

Table 0-2: 25SP Short Circuit Results

VOLTAGE (KV)	MAX. CURRENT (KA)	MAX KA CHANGE	MAX %CHANGE
69	13.968	0.019	0.14%
138	45.775	0.039	0.09%
345	34.806	0.099	0.29%
Max	45.775	0.039	0.09%

DYNAMIC STABILITY ANALYSIS

SPP performed a dynamic stability analysis to identify the impact of the inverter configuration change and other modifications to GEN-2017-164/178 & 2024-SR11. 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-2017-164/178 & 2024-SR11 configuration of 69 x PE FS4200 / 21 x PE FP4200 and 59x PE FP4200 Inverters (REGCA1). This stability analysis was performed using PTI's PSS/E version 34.8.0 software.

The modifications requested for the GEN-2017-164/178 & 2024-SR11 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-2017-164/178 & 2024-SR11 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.

The following system adjustments were made to address pre-existing issues that are not attributed to the modification request:

1. Disable drive train model (WTDTA1) for busses 51565 and 515652
2. Multiple overvoltage protection relays were disabled.
3. Minute impedance changes to faulted lines to help PSSE fault analysis numerical stability.
4. Acceleration factors of multiple faults were adjusted

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2017-164/178 & 2024-SR11 and other current and prior

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

queued projects in their cluster group[3]. In addition, voltages of five (5) buses away from the POI of GEN-2017-164/178 & 2024-SR11 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 524 (OKGE), 327 (EES), 330 (AECI), 515 (SPA), 520 (AEP), 523 (GRDA), 525 (WFEC), 526 (SPS), 527(OMPA), 534 (SUNC), and 536 (WERE) 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 faults for GEN-2017-164/178 & 2024-SR11 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
FLT9001-3PH	P1	3 phase fault on the G17-164-178 (770085) to WOODRNG7 (514715) 345 kV line CKT 1, near G17-164-178. a. Apply fault at the G17-164-178 345 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on the WOODRNG4 (514714) to OTTER 4 (514708) 138 kV line CKT 1, near WOODRNG4. a. Apply fault at the WOODRNG4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1	3 phase fault on the OTTER 4 (514708) to WRVALLY4 (514713) 138 kV line CKT 1, near OTTER 4. a. Apply fault at the OTTER 4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line.

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

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.
FLT9004-3PH	P1	3 phase fault on the ARMIFTWD4 (515694) to OTTER 4 (514708) 138 kV line CKT 1, near ARMIFTWD4. a. Apply fault at the ARMIFTWD4 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 MARSHL 4 (514733) to WOODRNG4 (514714) 138 kV line CKT 1, near MARSHL 4 . a. Apply fault at the MARSHL 4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9006-3PH	P1	3 phase fault on the CTNWOOD4 (514827) to MARSHL 4 (514733) 138 kV line CKT 1, near CTNWOOD4. a. Apply fault at the CTNWOOD4 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 MARSHAL4 (521006) to MARSHL 4 (514733) 138 kV line CKT Z1, near MARSHAL4. a. Apply fault at the MARSHAL4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 phase fault on the FRMNTAP4 (514709) to WOODRNG4 (514714) 138 kV line CKT 1, near FRMNTAP4. a. Apply fault at the FRMNTAP4 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 FARIRMON4 (514712) to FRMNTAP4 (514709) 138 kV line CKT 1, near FARIRMON4. a. Apply fault at the FARIRMON4 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.
FLT9010-3PH	P1	3 phase fault on the SO4TH 4 (514731) to FRMNTAP4 (514709) 138 kV line CKT 1, near SO4TH 4 . a. Apply fault at the SO4TH 4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9011-3PH	P1	3 phase fault on the SO4TH 4 (514731) to WAUKOTP4 (514711) 138 kV line CKT 1, near SO4TH 4 . a. Apply fault at the SO4TH 4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9012-3PH	P1	3 phase fault on the WAUKOTP4 (514711) to WOODRNG4 (514714) 138 kV line CKT 1, near WAUKOTP4. a. Apply fault at the WAUKOTP4 138 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9013-3PH	P1	3 phase fault on the WAUKMI4 (514710) to WAUKOTP4 (514711) 138 kV line CKT 1, near WAUKMI4. a. Apply fault at the WAUKMI4 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 REDNGTN7 (515875) to WOODRNG7 (514715) 345 kV line CKT 1, near REDNGTN7. a. Apply fault at the REDNGTN7 345 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9015-3PH	P1	3 phase fault on the REDDIRT7 (515877) to REDNGTN7 (515875) 345 kV line CKT Z1, near REDDIRT7. a. Apply fault at the REDDIRT7 345 kV bus. b. Clear fault after 7 cycles by tripping the faulted line.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		c. Wait 7 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 MATHWSN7 (515497) to REDNGTN7 (515875) 345 kV line CKT 1, near MATHWSN7. a. Apply fault at the MATHWSN7 345 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 7 cycles, then trip the line in (b) and remove fault.
FLT9017-3PH	P1	3 phase fault on the TATONGA7 (515407) to MATHWSN7 (515497) 345 kV line CKT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 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 TATONGA7 (515407) to MATHWSN7 (515497) 345 kV line CKT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 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 TRAVERSE3 (900001) to MATHWSN7 (515497) 345 kV line CKT 1, near TRAVERSE3. a. Apply fault at the TRAVERSE3 345 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9020-3PH	P1	3 phase fault on the NORTWST7 (514880) to MATHWSN7 (515497) 3445 kV line CKT 1, near NORTWST7. a. Apply fault at the NORTWST7 3445 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 CIMARON7 (514901) to MATHWSN7 (515497) 345 kV line CKT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 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.
FLT9022-3PH	P1	3 phase fault on the CIMARON7 (514901) to MATHWSN7 (515497) 345 kV line CKT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9023-3PH	P1	3 phase fault on the SKELTON7 (515990) to WOODRNG7 (514715) 345 kV line CKT 1, near SKELTON7. a. Apply fault at the SKELTON7 345 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9024-3PH	P1	3 phase fault on the GEN-2016-128 (588190) to SKELTON7 (515990) 138 kV line CKT 1, near GEN-2016-128. a. Apply fault at the GEN-2016-128 138 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.
FLT9025-3PH	P1	3 phase fault on the HUNTERS7 (515476) to WOODRNG7 (514715) 345 kV line CKT 1, near HUNTERS7. a. Apply fault at the HUNTERS7 345 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 CHSHLMV7 (515477) to HUNTERS7 (515476) 345 kV line CKT 1, near CHSHLMV7. a. Apply fault at the CHSHLMV7 345 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 RENFROW7 (515543) to HUNTERS7 (515476) 345 kV line CKT 1, near RENFROW7. a. Apply fault at the RENFROW7 345 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.
FLT9028-3PH	P1	3 phase fault on the G18-128-TAP (763421) to RENFROW7 (515543) 345 kV line CKT 1, near G18-128-TAP. a. Apply fault at the G18-128-TAP 345 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 GRNTWD 7 (515646) to RENFROW7 (515543) 345 kV line CKT 1, near GRNTWD 7. a. Apply fault at the GRNTWD 7 345 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 GEN-2017-203 (760809) to RENFROW7 (515543) 345 kV line CKT 1, near GEN-2017-203. a. Apply fault at the GEN-2017-203 345 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 PINTAIL7 (516010) to WOODRNG7 (514715) 345 kV line CKT 1, near PINTAIL7. a. Apply fault at the PINTAIL7 345 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.
FLT9032-3PH	P1	3 phase fault on the KINGWD 7 (516019) to PINTAIL7 (516010) 345 kV line CKT Z1, near KINGWD 7. a. Apply fault at the KINGWD 7 345 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.
FLT9033-3PH	P1	3 phase fault on the SOONER 7 (514803) to PINTAIL7 (516010) 345 kV line CKT 1, near SOONER 7. a. Apply fault at the SOONER 7 345 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.
FLT9034-3PH	P1	3 phase fault on the WEKIWA-7 (509755) to SOONER 7 (514803) 345 kV line CKT 1, near WEKIWA-7. a. Apply fault at the WEKIWA-7 345 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.
FLT9035-3PH	P1	3 phase fault on the G15-066T (560056) to SOONER 7 (514803) 345 kV line CKT 1, near G15-066T. a. Apply fault at the G15-066T 345 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.
FLT9036-3PH	P1	3 phase fault on the G16-199-TAP (587804) to SOONER 7 (514803) 345 kV line CKT 1, near G16-199-TAP. a. Apply fault at the G16-199-TAP 345 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.
FLT9037-3PH	P1	3 phase fault on the RANCHRD7 (515576) to SOONER 7 (514803) 345 kV line CKT 1, near RANCHRD7. a. Apply fault at the RANCHRD7 345 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.
FLT9038-3PH	P1	3 phase fault on the THUNDER7 (515894) to SOONER 7 (514803) 345 kV line CKT 1, near THUNDER7. a. Apply fault at the THUNDER7 345 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.
FLT9039-3PH	P1	3 phase fault on the WOODRNG7 138kV (514715)/ 138 kV (514714)/ 13.8 kV (515770) XFMR CKT 1, near WOODRNG7 138 kV.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		a. Apply fault at the WOODRNG7 138 kV bus. b. Clear fault after 7 cycles and trip the faulted XFMR.
FLT9040-3PH	P1	3 phase fault on the RDDIRT21 138kV (515879)/ 345 kV (515877)/ 12.5 kV (515885) XFMR CKT 1, near RDDIRT21 138 kV. a. Apply fault at the RDDIRT21 138 kV bus. b. Clear fault after 7 cycles and trip the faulted XFMR.
FLT9041-3PH	P1	3 phase fault on the RDDIRT11 138kV (515878)/ 345 kV (515877)/ 12.5 kV (515884) XFMR CKT 1, near RDDIRT11 138 kV. a. Apply fault at the RDDIRT11 138 kV bus. b. Clear fault after 7 cycles and trip the faulted XFMR.
FLT9042-3PH	P1	3 phase fault on the GEN-2016-128 138kV (588190)/ 34.5 kV (588191) XFMR CKT 1, near GEN-2016-128 138 kV. a. Apply fault at the GEN-2016-128 138 kV bus. b. Clear fault after 7 cycles and trip the faulted XFMR.
FLT9043-3PH	P1	3 phase fault on the SKELTON7 138kV (515990)/ 34.5 kV (515991)/ 13.8 kV (515992) XFMR CKT 1, near SKELTON7 138 kV. a. Apply fault at the SKELTON7 138 kV bus. b. Clear fault after 7 cycles and trip the faulted XFMR.
FLT9044-3PH	P1	3 phase fault on the CHSHLMV7 345kV (515477)/ 34.5 kV (515479)/ 13.2 kV (515482) XFMR CKT 1, near CHSHLMV7 345 kV. a. Apply fault at the CHSHLMV7 345 kV bus. b. Clear fault after 7 cycles and trip the faulted XFMR.
FLT9045-3PH	P1	3 phase fault on the CHSHMVW1 345kV (515484)/ 345 kV (515477)/ 13.2 kV (515485) XFMR CKT 1, near CHSHMVW1 345 kV. a. Apply fault at the CHSHMVW1 345 kV bus. b. Clear fault after 7 cycles and trip the faulted XFMR.
FLT9046-3PH	P1	3 phase fault on the RENFROW4 138kV (515544)/ 345 kV (515543)/ 13.8 kV (515545) XFMR CKT 1, near RENFROW4 138 kV. a. Apply fault at the RENFROW4 138 kV bus. b. Clear fault after 7 cycles and trip the faulted XFMR.
FLT9047-3PH	P1	3 phase fault on the SOONER 4 138kV (514802)/ 345 kV (514803)/ 13.8 kV (515760) XFMR CKT 1, near SOONER 4 138 kV.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		a. Apply fault at the SOONER 4 138 kV bus. b. Clear fault after 7 cycles and trip the faulted XFMR.
FLT9048-3PH	P1	3 phase fault on the SOONER2G 20kV (514806)/ 345 kV (514803) XFMR CKT 1, near SOONER2G 20 kV. a. Apply fault at the SOONER2G 20 kV bus. b. Clear fault after 7 cycles and trip the faulted XFMR.
FLT9049-3PH	P1	3 phase fault on the KNGWDL21 138kV (516018)/ 345 kV (516019)/ 13.2 kV (516021) XFMR CKT 1, near KNGWDL21 138 kV. a. Apply fault at the KNGWDL21 138 kV bus. b. Clear fault after 7 cycles and trip the faulted XFMR.
FLT9050-3PH	P1	3 phase fault on the KINGWD 7 345kV (516019)/ 34.5 kV (516017)/ 13.2 kV (516020) XFMR CKT 1, near KINGWD 7 345 kV. a. Apply fault at the KINGWD 7 345 kV bus. b. Clear fault after 7 cycles and trip the faulted XFMR.
FLT1001-SLG	P4	Apply single-phase fault at WOODRNG7 on the 345kV bus after 16 cycles a. Trip the WOODRNG7 to HUNTERS7 Transmission Line Ckt 1 b. Trip the WOODRNG7 to PINTAIL7 Transmission Line Ckt 1
FLT1002-SLG	P4	Apply single-phase fault at WOODRNG7 on the 345kV bus after 16 cycles a. Trip the WOODRNG7 to PINTAIL7 Transmission Line Ckt 1 b. Trip the WOODRNG7 to REDNGTN7 Transmission Line Ckt 1
FLT1003-SLG	P4	Apply single-phase fault at WOODRNG7 on the 345kV bus after 16 cycles a. Trip the WOODRNG7 to REDNGTN7 Transmission Line Ckt 1 b. Trip the WOODRNG7 to SKELTON7 Transmission Line Ckt 1
FLT1004-SLG	P4	Apply single-phase fault at WOODRNG7 on the 345kV bus after 16 cycles a. Trip the WOODRNG7 to SKELTON7 Transmission Line Ckt 1 b. Trip the WOODRNG7 345/138/13.8kV Transformer Ckt 1
FLT1005-SLG	P4	Apply single-phase fault at WOODRNG7 on the 345kV bus after 16 cycles a. Trip the WOODRNG7 345/138/13.8kV Transformer Ckt 1 b. Trip the WOODRNG7 to HUNTERS7 Transmission Line Ckt 1

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT1006-SLG	P4	Apply single-phase fault at WOODRNG4 on the 138kV bus after 16 cycles a. Trip the WOODRNG4 138/345/13.8kV Transformer Ckt 1 b. Trip the WOODRNG4 to MARSHL 4 Transmission Line Ckt 1
FLT1007-SLG	P4	Apply single-phase fault at WOODRNG4 on the 138kV bus after 16 cycles a. Trip the WOODRNG4 to MARSHL 4 Transmission Line Ckt 1 b. Trip the WOODRNG4 to WAUKOTP4 Transmission Line Ckt 1
FLT1008-SLG	P4	Apply single-phase fault at WOODRNG4 on the 138kV bus after 16 cycles a. Trip the WOODRNG4 to WAUKOTP4 Transmission Line Ckt 1 b. Trip the WOODRNG4 to FRMNTAP4 Transmission Line Ckt 1
FLT1009-SLG	P4	Apply single-phase fault at WOODRNG4 on the 138kV bus after 16 cycles a. Trip the WOODRNG4 to FRMNTAP4 Transmission Line Ckt 1 b. Trip the WOODRNG4 to OTTER 4 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-2017-164/178 & 2024-SR11 Dynamic Stability Results

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

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

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	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
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
FLT9039-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9040-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9041-3PH	Pass	Pass	Stable	Pass	Pass	Stable

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT9042-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9043-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9044-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9045-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9046-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9047-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9048-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9049-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9050-3PH	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
FLT1007-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SLG	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-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-2017-164/178 &

2024-SR11 modification. These issues were not attributed to the GEN-2017-164/178 & 2024-SR11 modification request.

There were no damping or voltage recovery violations attributed to the GEN-2017-164/178 & 2024-SR11modification 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-2017-164/178 & 2024-SR11 (302 MW) and the total capability (302 MW) exceed the GIA Interconnection Service amount, 302 MW, as listed in Appendix A of the GIA. The GEN-2017-164/178 & 2024-SR11 inverters are rated at 3.691 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-2017-164/178 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.