Submitted to

Southwest Power Pool

Southwest Power Pool

Report On

GEN-2007-043 and GEN-2016-131 Modification Request Impact Study

Revision R1

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anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
11/30/2021	Aneden Consulting	Initial Report Issued.

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2007-043 and GEN-2016-131, two active Generation Interconnection Requests (GIR) with a point of interconnection (POI) at the Minco 345 kV Substation.

The GEN-2007-043 and GEN-2016-131 projects interconnect in the Oklahoma Gas & Electric (OKGE) control area with a combined capacity of 202.5 MW as two project phases, Minco I and Minco II, as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2007-043 and GEN-2016-131 to keep the Minco I configuration of 62 x GE 1.62 MW but change the Minco II turbine configuration to 61 x GE 1.62 MW + 2 x GE 2.32 MW for a total combined capacity of 203.9 MW. The combined generating capacity for GEN-2007-043 and GEN-2016-131 (203.9) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 202.5 MW, as listed in Appendix A. 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. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

In addition, the modification request included changes to the collection system and generator step-up transformers. The existing and modified configurations for GEN-2007-043 and GEN-2016-131 are shown in Table ES-2.

Table ES-1: GEN-2007-043 & GEN-2016-131 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	Capacity (MW)
GEN-2007-043	Minco 345 kV (514801)	Minco I: 62 x GE 1.62 MW = 100.44 MW Minco II: 63 x GE 1.62 MW = 102.06 MW	200
GEN-2016-131	Minco 345 kV (514801)		2.5
		Total Combined Capacity	202.5

Table ES-2: GEN-2007-043 & GEN-2016-131 Modification Request

Facility	Existing	Modification		
Point of Interconnection	Minco 345 kV (514801)	Minco 345 kV (514801)		
Configuration/ Capacity	Minco I: 62 x GE 1.62 MW = 100.44 MW Minco II: 63 x GE 1.62 MW = 102.06 MW Total Capacity = 202.5 MW	Minco I: 62 x GE 1.62 MW = 100.44 MW Minco II: 61 x GE 1.62 MW + 2 x GE 2.32 MW = 103.46 MW Total Capacity = 203.9 MW PPC to limit POI to 202.5 MW		
Generation Interconnection Line	Length = 0.04 miles R = 0.000004 pu X = 0.000030 pu B = 0.000270 pu Rating A/B MVA = 1010 MVA	Length = 0.04 miles R = 0.000004 pu X = 0.000030 pu B = 0.000270 pu Rating A/B MVA = 1010 MVA		
Main Substation Transformer[1]	X12 = 7.969% R12 = 0.139%, X23 = 2.1% R23 = 0.0%, X13 = 11.5% R13 = 0.0%, Winding MVA = 135 MVA, Winding 1 & 2 Rating MVA = 225 MVA, Winding 3 Rating MVA = 75 MVA	X12 = 7.969% R12 = 0.139%, X23 = 2.1% R23 = 0.0%, X13 = 11.5% R13 = 0.0%, Winding MVA = 135 MVA, Winding 1 & 2 Rating MVA = 225 MVA, Winding 3 Rating MVA = 75 MVA		
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 125 (GEWTG2) X = 5.7% R = 0.76%, Winding MVA = 225 MVA, Rating MVA = 225 MVA	Gen 1 Equivalent Qty: 62 (REGCAU1) X = 5.699%, R = 0.759%, Winding MVA = 111.6 MVA, Rating MVA = 111.6 MVA	Gen 2 Equivalent Qty: 61 (REGCAU1) X = 5.699%, R = 0.759%, Winding MVA = 109.8 MVA, Rating MVA = 109.8 MVA	Gen 3 Equivalent Qty: 2 (REGCAU1) X = 5.699%, R = 0.759%, Winding MVA = 5.354 MVA, Rating MVA[2] = 5.4 MVA
Equivalent Collector Line[3]	R = 0.005932 pu X = 0.007968 pu B = 0.137213 pu	R = 0.005338 pu X = 0.007527 pu B = 0.129644 pu		
Reactive Power Devices	4 x 15 MVAR 34.5 kV Capacitor Bank 1 x 12 MVAR 34.5 kV Reactor	4 x 15 MVAR 34.5 kV Capacitor Bank 1 x 12 MVAR 34.5 kV Reactor		

1) X/R based on Winding MVA, 2) Rating rounded in PSS/E, 3) all pu are on 100 MVA Base

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.81% compared to the DISIS-2017-001 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, GE, the change in stability model from GEWTG2 to REGCAU1, project capacity increase, and the use of a PPC required short circuit and dynamic stability analyses. The scope of this modification request study included charging current compensation analysis, short circuit analysis, and dynamic stability analysis.

Aneden performed the analyses using the modification request data based on the DISIS-2017-001 Group 1 study models:

1. 2019 Winter Peak (2019WP),
2. 2021 Light Load (2021LL)
3. 2021 Summer Peak (2021SP),
4. 2028 Summer Peak (2028SP)

Aneden reviewed the GIRs that shared the same POI, Minco 345 kV, and updated as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the GEN-2011-010 and GEN-2014-005 project configurations in the base models. All analyses were performed using the PTI PSS/E version 33 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak models showed that the GEN-2007-043 and GEN-2016-131 project needed 12.9 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 13.8 MVAr found for the existing GEN-2007-043 and GEN-2016-131 configuration calculated using the DISIS-2017-001 models. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind 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 results from the short circuit analysis with the updated topology showed that the maximum GEN-2007-043 and GEN-2016-131 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2007-043 and GEN-2016-131 POI was no greater than 0.92 kA for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2007-043 and GEN-2016-131 generators online were below 46 kA for the 2021SP and 2028SP models.

The dynamic stability analysis was performed using PTI PSS/E version 33.10 software and the four modified study models, 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak. Up to 53 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

The results of the dynamic stability analysis showed that there were numerous existing base case issues that were mitigated prior to studying the modification request. Several case adjustments were made including updating the GEN-2015-048, GEN-2016-045, and GEN-2016-057 configurations were updated with the latest project configurations in the base models in order to avoid base case stability issues. In addition, there were two other types of existing stability oscillations. First, EFD oscillations were found for many faults studied in the 21LL case from the REDBUD units (514899, 514900, 514905, 514910, 514940, 514942). Second, EFD oscillations were found for many faults studied in the 28SP case from the Spring Creek units (514882, 514883). These issues were observed in the DISIS and modification cases so they were not attributed to the GEN-2007-043 and GEN-2016-131 modification.

There were no damping or voltage recovery violations attributed to the GEN-2007-043 and GEN-2016-131 project 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.

1.0 Scope of Study

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2007-043 and GEN-2016-131. 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 PTI PSS/E version 33 software. The results of each analysis are presented in the following sections.

1.1 Power Flow

To determine whether power flow analysis is required, SPP evaluates the difference in the real power output at the POI between the DISIS-2017-001 power flow configuration and the requested modification. Power flow analysis is included if the difference has a significant impact on the results of the DISIS study.

1.2 Stability Analysis, Short Circuit Analysis

To determine whether stability and short circuit analyses are required, SPP evaluates the difference between the turbine parameters and, if needed, the 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.

1.3 Charging Current Compensation 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.

1.4 Study Limitations

The assessments and conclusions provided in this report are based on assumptions and information provided to Aneden by others. While the assumptions and information provided may be appropriate for the purposes of this report, Aneden does not guarantee that those conditions assumed will occur. In addition, Aneden did not independently verify the accuracy or completeness of the information provided. As such, the conclusions and results presented in this report may vary depending on the extent to which actual future conditions differ from the assumptions made or information used herein.

2.0 Project and Modification Request

The GEN-2007-043 and GEN-2016-131 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the Minco 345 kV Substation. At the time of the posting of this report, GEN-2007-043 and GEN-2016-131 were active Interconnection Requests with queue statuses of “IA FULLY EXECUTED/COMMERCIAL OPERATION.” GEN-2007-043 and GEN-2016-131 are wind farms and have maximum summer and winter queue capacities of 200 MW and 2.5 MW respectively with Energy Resource Interconnection Service (ERIS).

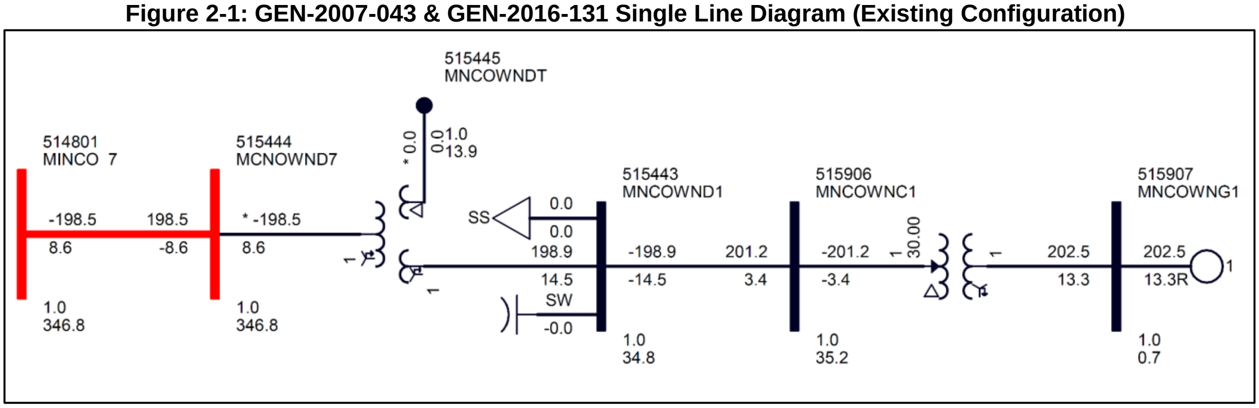
The GEN-2007-043 and GEN-2016-131 projects were originally studied in the ICS-2008-001[1] and DISIS-2016-002 studies respectively. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2007-043 and GEN-2016-131 configuration.

The GEN-2007-043 and GEN-2016-131 projects interconnect in the Oklahoma Gas & Electric (OKGE) control area across two phases, Minco I and Minco II, with a combined capacity of 202.5 MW as shown in Table 2-1 below.

Table 2-1: GEN-2007-043 & GEN-2016-131 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	Capacity (MW)
GEN-2007-043	Minco 345 kV (514801)	Minco I: 62 x GE 1.62 MW = 100.44 MW Minco II: 63 x GE 1.62 MW = 102.06 MW	200
GEN-2016-131	Minco 345 kV (514801)		2.5
		Total Combined Capacity	202.5

Figure 2-1: GEN-2007-043 & GEN-2016-131 Single Line Diagram (Existing Configuration)



This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2007-043 and GEN-2016-131 to keep the Minco I configuration of 62 x GE 1.62 MW but change Minco II from the previously studied 63 x GE 1.62 MW to a turbine configuration of 61 x GE 1.62 MW + 2 x GE 2.32 MW for a total combined capacity of 203.9 MW. The combined generating capacity for GEN-2007-043 and GEN-2016-131 (203.9 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, (202.5 MW), as listed in Appendix A. The customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. The requested modification

[1] Impact Cluster Study for Generation Interconnection Requests, November 2013

includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI. In addition, the modification request included changes to the collection system and generator step-up transformers. Figure 2-2 shows the power flow model single line diagram for the GEN-2007-043 and GEN-2016-131 modification. The existing and modified configurations for GEN-2007-043 and GEN-2016-131 are shown in
Table 2-2.

Figure 2-2: GEN-2007-043 & GEN-2016-131 Single Line Diagram (Modification Configuration)

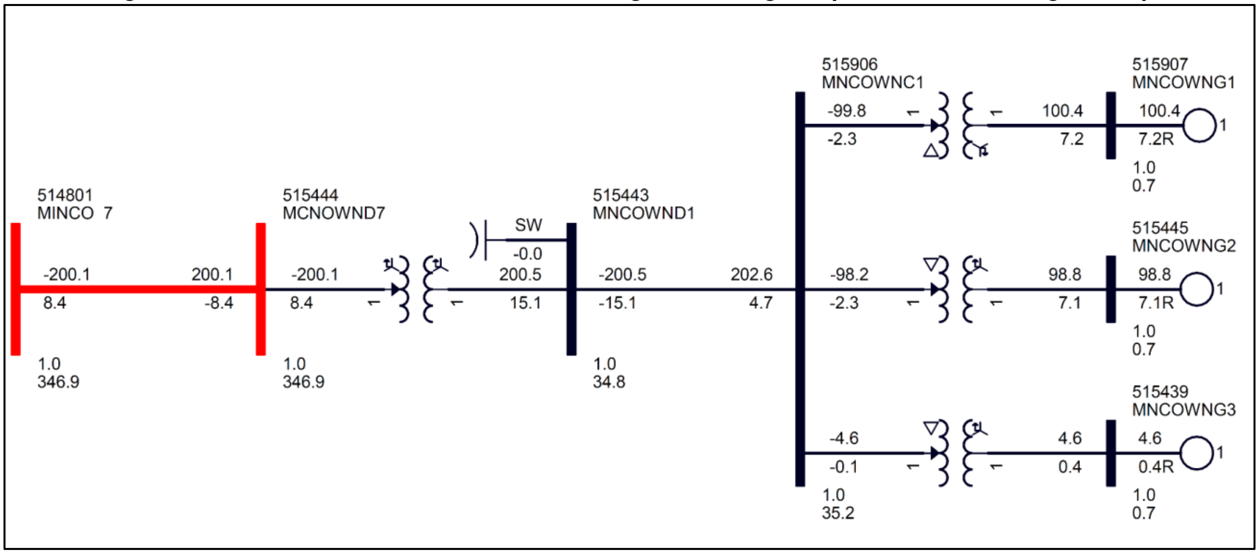


Table 2-2: GEN-2007-043 & GEN-2016-131 Modification Request

Facility	Existing	Modification		
Point of Interconnection	Minco 345 kV (514801)	Minco 345 kV (514801)		
Configuration/Capacity	Minco I: 62 x GE 1.62 MW = 100.44 MW Minco II: 63 x GE 1.62 MW = 102.06 MW Total Capacity = 202.5 MW	Minco I: 62 x GE 1.62 MW = 100.44 MW Minco II: 61 x GE 1.62 MW + 2 x GE 2.32 MW = 103.46 MW Total Capacity = 203.9 MW PPC to limit POI to 202.5 MW		
Generation Interconnection Line	Length = 0.04 miles R = 0.000004 pu X = 0.000030 pu B = 0.000270 pu Rating A/B MVA = 1010 MVA	Length = 0.04 miles R = 0.000004 pu X = 0.000030 pu B = 0.000270 pu Rating A/B MVA = 1010 MVA		
Main Substation Transformer[1]	X12 = 7.969% R12 = 0.139%, X23 = 2.1% R23 = 0.0%, X13 = 11.5% R13 = 0.0%, Winding MVA = 135 MVA, Winding 1 & 2 Rating MVA = 225 MVA, Winding 3 Rating MVA = 75 MVA	X12 = 7.969% R12 = 0.139%, X23 = 2.1% R23 = 0.0%, X13 = 11.5% R13 = 0.0%, Winding MVA = 135 MVA, Winding 1 & 2 Rating MVA = 225 MVA, Winding 3 Rating MVA = 75 MVA		
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 125 (GEWTG2) X = 5.7% R = 0.76%, Winding MVA = 225 MVA, Rating MVA = 225 MVA	Gen 1 Equivalent Qty: 62 (REGCAU1) X = 5.699%, R = 0.759%, Winding MVA = 111.6 MVA, Rating MVA = 111.6 MVA	Gen 2 Equivalent Qty: 61 (REGCAU1) X = 5.699%, R = 0.759%, Winding MVA = 109.8 MVA, Rating MVA = 109.8 MVA	Gen 3 Equivalent Qty: 2 (REGCAU1) X = 5.699%, R = 0.759%, Winding MVA = 5.354 MVA, Rating MVA[2] = 5.4 MVA
Equivalent Collector Line[3]	R = 0.005932 pu X = 0.007968 pu B = 0.137213 pu	R = 0.005338 pu X = 0.007527 pu B = 0.129644 pu		
Reactive Power Devices	4 x 15 MVAR 34.5 kV Capacitor Bank 1 x 12 MVAR 34.5 kV Reactor	4 x 15 MVAR 34.5 kV Capacitor Bank 1 x 12 MVAR 34.5 kV Reactor		

1) X/R based on Winding MVA, 2) Rating rounded in PSS/E, 3) all pu are on 100 MVA Base

3.0 Existing vs Modification Comparison

To determine which analyses are required for the Study, the differences between the existing configuration and the requested modification were evaluated. Aneden performed this comparison and the resulting analyses using a set of modified study models developed based on the modification request data and the DISIS-2017-001 Group 1 study models.

Aneden reviewed the GIRs that shared the same POI, Minco 345 kV, and updated as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the GEN-2011-010 and GEN-2014-005 project configurations in the base models.

In addition, the GEN-2015-048, GEN-2016-045, and GEN-2016-057 configurations were updated with the latest project configurations in the base models in order to avoid base case stability issues.

The methodology and results of the comparisons are described below. The analysis was completed using PSS/E version 33 software.

3.1 POI Injection Comparison

The real power injection at the POI was determined using PSS/E to compare the DISIS-2017-001 power flow configuration and the requested modifications with the PPC in place for GEN-2007-043 and GEN-2016-131. The percentage change in the POI injection was then evaluated. If the MW difference was determined to be significant, power flow analysis would be performed to assess the impact of the modification request.

SPP determined that power flow analysis was not required due to the insignificant change (increase of 0.81%) in the real power output at the POI between the studied DISIS-2017-001 power flow configuration and requested modification shown in Table 3-1.

Table 3-1: GEN-2007-043 & GEN-2016-131 POI Injection Comparison

Interconnection Request	Existing POI Injection (MW)	MRIS POI Injection (MW)	POI Injection Difference %
GEN-2007-043 & GEN-2016-131	198.5	200.1	0.81%

3.2 Turbine Parameters Comparison

SPP determined that while the modification used the same turbine manufacturer, GE, the change in stability model from GEWTG2 to REGCAU1, the project capacity increase, and the use of a PPC required short circuit and dynamic stability analysis. 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.

3.3 Equivalent Impedance Comparison Calculation

As the turbine 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.

4.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2007-043 and GEN-2016-131 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.

4.1 Methodology and Criteria

The GEN-2007-043 and GEN-2016-131 generators were switched out of service while other collection 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).

4.2 Results

The results from the analysis showed that the GEN-2007-043 and GEN-2016-131 project needed approximately 12.9 MVAr of compensation at its project substation, to reduce the POI MVAr to zero. This is a decrease from the 13.8 MVAr found for the existing GEN-2007-043 and GEN-2016-131 configuration calculated using the DISIS-2017-001 models. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the existing configuration. Figure 4-2 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-2007-043 and GEN-2016-131 are shown in Table 4-1.

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 4-1: Shunt Reactor Size for Low Wind Study (Modification)

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)			
			19WP	21SP	21LL	28SP
GEN-2007-043 & GEN-2016-131	514801	Minco 345 kV	12.9	12.9	12.9	12.9

Figure 4-1: GEN-2007-043 & GEN-2016-131 Single Line Diagram (Existing Shunt Reactor)

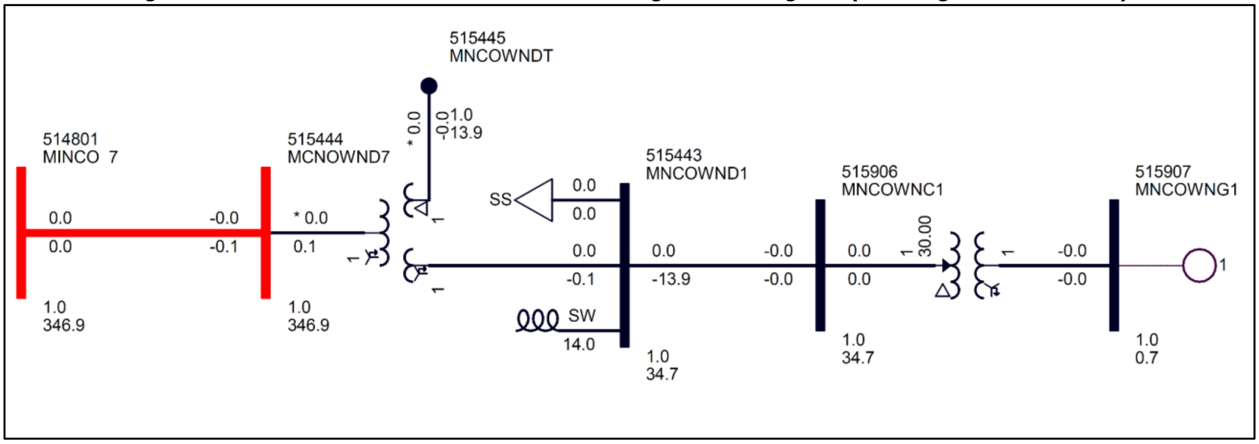
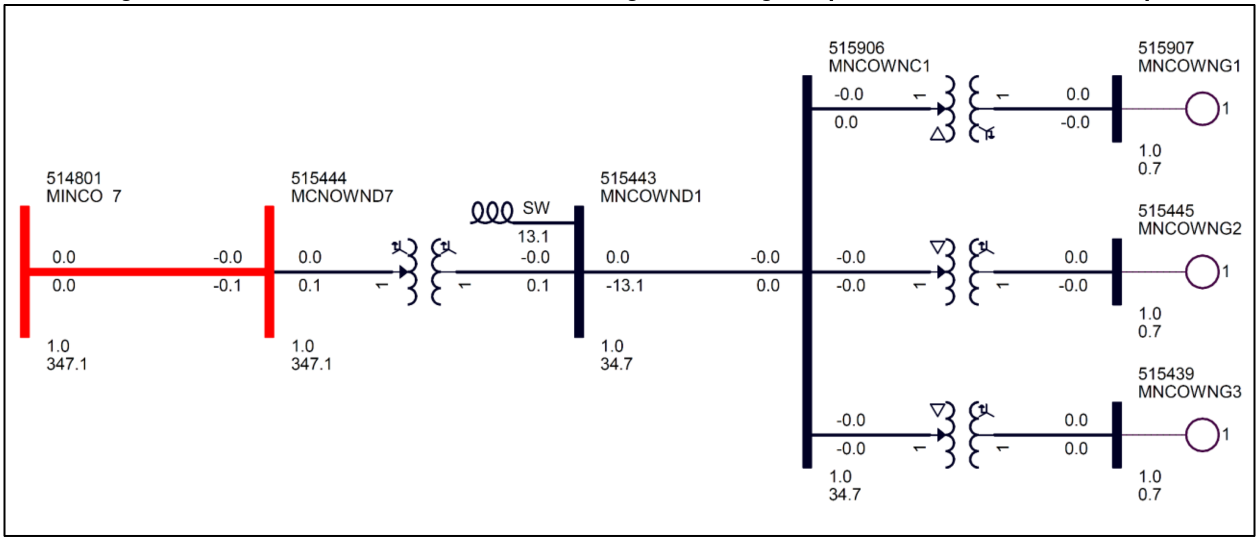


Figure 4-2: GEN-2007-043 & GEN-2016-131 Single Line Diagram (Modification Shunt Reactor)



5.0 Short Circuit Analysis

A short circuit study was performed using the 2021SP and 2028SP models for GEN-2007-043 and GEN-2016-131. The detailed results of the short circuit analysis are provided in Appendix B.

5.1 Methodology

The short circuit analysis included applying a 3-phase fault on buses up to 5 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-2007-043 and GEN-2016-131 online.

5.2 Results

The results of the short circuit analysis for the 2021SP and 2028SP models are summarized in Table 5-1 through Table 5-3 respectively. The GEN-2007-043 and GEN-2016-131 POI bus fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 18.32 kA with the GEN-2007-043 and GEN-2016-131 project online.

The maximum fault current calculated within 5 buses of the GEN-2007-043 and GEN-2016-131 POI was less than 46 kA for the 2021SP and 2028SP models respectively. The maximum GEN-2007-043 and GEN-2016-131 contribution to three-phase fault current was about 5.3% and 0.92 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2021SP	17.27	18.19	0.92	5.3%
2028SP	17.40	18.32	0.92	5.3%

Table 5-2: 2021SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	16.5	0.01	0.0%
138	45.0	0.12	0.3%
230	8.7	0.01	0.1%
345	34.5	0.92	5.3%
Max	**45.0**	**0.92**	**5.3%**

Table 5-3: 2028SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	20.1	0.01	0.0%
138	45.0	0.11	0.3%
230	8.7	0.01	0.1%
345	34.6	0.92	5.3%
Max	**45.0**	**0.92**	**5.3%**

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine configuration change and other modifications to the GEN-2007-043 and GEN-2016-131 project. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix C. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix A. The simulation plots can be found in Appendix D.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested GEN-2007-043 and GEN-2016-131 configuration of Minco I, 62 x GE 1.62 (REGCAU1), and Minco II, 61 x GE 1.62 MW (REGCAU1) + 2 x GE 2.32 MW(REGCAU1). This stability analysis was performed using PTI's PSS/E version 33.10 software.

The stability models were developed using the DISIS-2017-001 Group 1 models. The modifications requested for the GEN-2007-043 and GEN-2016-131 project were used to create modified stability models for this impact study. Aneden reviewed the GIRs that shared the same POI, Minco 345 kV, and updated as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the GEN-2011-010 and GEN-2014-005 project configurations in the base models.

The following system adjustment was made to address existing base case issues that are not attributed to the modification request:

1. GEN-2015-048, GEN-2016-045, and GEN-2016-057 were updated with the latest project configurations
2. The shunt reactors connected at the Northwest 345/138/13.8kV transformers (514885, 515742, 515743) were switched offline in the 19WP case to avoid steady state low voltage issues
3. The REGCAU1 model CON(J+11) Iqrmax and CON(J+12) Iqrmin were changed from 999 and -999 to 2 and -2 respectively for generators GRNTWDG (515660, 515661) and KAYWNDG (515651, 515652)
4. The governor model GGOV1 CON(J+23) parameter was changed from 1.0 to 0.002 for the OEC generators at buses 511939, 511940, 511942, and 511943

The modified dynamics model data for the GEN-2007-043 and GEN-2016-131 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.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2007-043 and GEN-2016-131 and other equally and prior queued projects in Group 1. In addition, voltages of five (5) buses away from the POI of GEN-2007-043 and GEN-2016-131 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 520 (AEPW), 524 (OKGE), 525 (WFEC), 526 (SPS), 531 (MIDW), 534 (SUNC), and 536 (WERE) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

6.2 Fault Definitions

Aneden simulated the faults previously simulated for GEN-2007-043 and GEN-2016-131 and developed additional fault events as required. The new set of faults were simulated using the modified study models. The fault events included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults. The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and the 2028 Summer Peak models.

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT45-3PH	P1	3 phase fault on the TRAVERSE1 (900001) to MATHWSN7 (515497) 345 kV line circuit 1, near TRAVERSE1. a. Apply fault at the TRAVERSE1 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G16-045-GEN1 (587303).** **Trip generator G16-045-GEN2 (587307).** **Trip generator G16-057-GEN1 (587383).** **Trip generator G16-057-GEN2 (587387).** **Trip generator G16-057-GEN3 (587380).** **Trip generator G16-057-GEN3 (587300).** 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.
FLT01-SB	P4	**Stuck Breaker at CIMARON7 (514901) at 345kV** a. Apply single phase fault at CIMARON7 bus. b. Clear fault after 16 cycles and trip the following elements c. CIMARON7 (514901) - MATHWSN7 (515497) 345kV line CKT 1 d. CIMARON7 345 kV (514901) / CIMARON4 138 kV (514898) / CIMARON11 13.8 kV (515714) transformer CKT 1.
FLT02-SB	P4	**Stuck Breaker at CIMARON7 (514901) at 345kV** a. Apply single phase fault at CIMARON7 bus. b. Clear fault after 16 cycles and trip the following elements c. CIMARON7 (514901) - DRAPER (514934) 345kV line CKT 1 d. CIMARON7 345 kV (514901) / CIMARON4 138 kV (514898) / CIMARON21 13.8 kV (515715) transformer CKT 1.
FLT03-SB	P4	**Stuck Breaker at CIMARON7 (514901)** a. Apply single phase fault at CIMARON7 bus. b. Clear fault after 16 cycles and trip the following elements c. CIMARON7 (514901) - MATHWSN7 (515497) 345kV line CKT 2. d. CIMARON7 (514901) - NORTWST7 (514880) 345kV line CKT 1.
FLT04-SB	P4	**Stuck Breaker at CIMARON7 (514901) at 345kV** a. Apply single phase fault at CIMARON7 bus. b. Clear fault after 16 cycles and trip the following elements c. CIMARON7 (514901) - FSHRTAP7 (515610) 345kV line CKT 1. **Trip generator CANADNG1 (515900).** **Trip generator CANADNG2 (515902).** **Trip generator KNGFSHR-GEN1 (515664).** **Trip generator KNGFSHR-GEN2 (515665).** d. CIMARON7 (514901) - MINCO 7 (514801) 345kV line CKT 1.
FLT9001-3PH	P1	3 phase fault on the MINCO 7 (514801) to CIMARON7 (514901) 345 kV line circuit 1, near MINCO 7. a. Apply fault at the MINCO 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.
FLT9002-3PH	P1	3 phase fault on the MINCO 7 (514801) to GRACMNT7 (515800) 345 kV line circuit 1, near MINCO 7. a. Apply fault at the MINCO 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.
FLT9003-3PH	P1	3 phase fault on the GRACMNT7 (515800) to GEN-2015-093 (563269) 345 kV line circuit 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G15-093-GEN1 (563272).** **Trip generator G15-093-GEN2 (563273).** 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.
FLT9004-3PH	P1	3 phase fault on the GRACMNT7 (515800) to G16-037-TAP (560078) 345 kV line circuit 1, near GRACMNT7. a. Apply fault at the GRACMNT7 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.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9005-3PH	P1	3 phase fault on the GRACMNT7 (515800) to G16-091-TAP (587744) 345 kV line circuit 1, near GRACMNT7. a. Apply fault at the GRACMNT7 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.
FLT9006-3PH	P1	3 phase fault on the G16-037-TAP (560078) to GEN-2016-037 (587230) 345 kV line circuit 1, near G16-037-TAP. a. Apply fault at the G16-037-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G16-037-GEN1 (587233).** 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.
FLT9007-3PH	P1	3 phase fault on the G16-037-TAP (560078) to CHISHOLM7 (511553) 345 kV line circuit 1, near G16-037-TAP. a. Apply fault at the G16-037-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 phase fault on the G16-091-TAP (587744) to L.E.S -7 (511468) 345 kV line circuit 1, near G16-091-TAP. a. Apply fault at the G16-091-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	P1	3 phase fault on the G16-091-TAP (587744) to GEN-2016-091 (587740) 345 kV line circuit 1, near G16-091-TAP. a. Apply fault at the G16-091-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G16-091-GEN1 (587743).** 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.
FLT9010-3PH	P1	3 phase fault on the G16-091-TAP (587744) to GEN-2016-095 (587770) 345 kV line circuit 1, near G16-091-TAP. a. Apply fault at the G16-091-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G16-095-GEN1 (587773).** 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.
FLT9011-3PH	P1	3 phase fault on the GRACMNT3 345 kV (515800) /138 kV (515802) /13.8kV (515801) XFMR CKT 1, near GRACMNT7 345kV. a. Apply fault at the GRACMNT7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9012-3PH	P1	3 phase fault on the CIMARON2 345 kV (514901) /138 kV (514898) /13.8kV (515715) XFMR CKT 1, near CIMARON7 345kV. a. Apply fault at the CIMARON7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9013-3PH	P1	3 phase fault on the CIMARON7 (514901) to MATHWSN7 (515497) 345 kV line circuit 1, near CIMARON7. a. Apply fault at the CIMARON7 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.
FLT9014-3PH	P1	3 phase fault on the CIMARON7 (514901) to NORTWST7 (514880) 345 kV line circuit 1, near CIMARON7. a. Apply fault at the CIMARON7 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.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9015-3PH	P1	3 phase fault on the CIMARON7 (514901) to FSHRTAP7 (515610) 345 kV line circuit 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator CANADNG1 (515900).** **Trip generator CANADNG2 (515902).** **Trip generator KNGFSHR-GEN1 (515664).** **Trip generator KNGFSHR-GEN2 (515665).** 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.
FLT9016-3PH	P1	3 phase fault on the CIMARON7 (514901) to DRAPER 7 (514934) 345 kV line circuit 1, near CIMARON7. a. Apply fault at the CIMARON7 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.
FLT9017-3PH	P1	3 phase fault on the DRAPER 7 (514934) to SEMINOL7 (515045) 345 kV line circuit 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.
FLT9018-3PH	P1	3 phase fault on the DRAPER4 345 kV (514934) /138 kV (514933) /13.8kV (515721) XFMR CKT 1, near DRAPER 7 345kV. a. Apply fault at the DRAPER 7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9019-3PH	P1	3 phase fault on the FSHRTAP7 (515610) to CANADN7 (515605) 345 kV line circuit 1, near FSHRTAP7. a. Apply fault at the FSHRTAP7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator CANADNG1 (515900).** **Trip generator CANADNG2 (515902).** 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.
FLT9020-3PH	P1	3 phase fault on the FSHRTAP7 (515610) to KNGFSHR7 (515600) 345 kV line circuit 1, near FSHRTAP7. a. Apply fault at the FSHRTAP7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator KNGFSHR-GEN1 (515664).** **Trip generator KNGFSHR-GEN2 (515665).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9021-3PH	P1	3 phase fault on the NORTWST7 (514880) to MATHWSN7 (515497) 345 kV line circuit 1, near NORTWST7. a. Apply fault at the NORTWST7 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.
FLT9022-3PH	P1	3 phase fault on the NORTWST4 345 kV (514880) /138 kV (514879) /13.8kV (514885) XFMR CKT 1, near NORTWST7 345kV. a. Apply fault at the NORTWST7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9023-3PH	P1	3 phase fault on the NORTWST7 (514880) to ARCADIA7 (514908) 345 kV line circuit 1, near NORTWST7. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9024-3PH	P1	3 phase fault on the NORTWST7 (514880) to SPRNGCK7 (514881) 345 kV line circuit 1, near NORTWST7. a. Apply fault at the NORTWST7 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.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9025-3PH	P1	3 phase fault on the MATHWSN7 (515497) to REDNGTN7 (515875) 345 kV line circuit 1, near MATHWSN7. a. Apply fault at the MATHWSN7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9026-3PH	P1	3 phase fault on the MATHWSN7 (515497) to TRAVERSE1 (900001) 345 kV line circuit 1, near MATHWSN7. a. Apply fault at the MATHWSN7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G16-045-GEN1 (587303).** **Trip generator G16-045-GEN2 (587307).** **Trip generator G16-057-GEN1 (587383).** **Trip generator G16-057-GEN2 (587387).** **Trip generator G16-057-GEN3 (587380).** **Trip generator G16-045-GEN2 (587300).** 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.
FLT9027-3PH	P1	3 phase fault on the MATHWSN7 (515497) to TATONGA7 (515407) 345 kV line circuit 1, near MATHWSN7. a. Apply fault at the MATHWSN7 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.
FLT9028-3PH	P1	3 phase fault on the MINCO 7 (514801) to MNCWND37 (515549) 345 kV line circuit 1, near MINCO 7. a. Apply fault at the MINCO 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G15-057-GEN1 (584953).** **Trip generator G15-057-GEN2 (584954).** **Trip generator G15-057-GEN3 (584955).** **Trip generator MNCO4G11 (515943).** **Trip generator G14-056-GEN2 (584064).** **Trip generator G14-056-GEN3 (584067).** **Trip generator G11-010_G14-005 (599117, 515551, 599119, 599120).** 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.
FLT9029-3PH	P1	3 phase fault on the MNCWND37 (515549) to GEN-2015-057 (584060) 345 kV line circuit 1, near MNCWND37. a. Apply fault at the MNCWND37 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G15-057-GEN1 (584953).** **Trip generator G15-057-GEN2 (584954).** **Trip generator G15-057-GEN3 (584955).** **Trip generator MNCO4G11 (515943).** **Trip generator G14-056-GEN2 (584064).** **Trip generator G14-056-GEN3 (584067).** 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.
FLT9030-3PH	P1	3 phase fault on the MCNWND31 345 kV (515549) /34.5 kV (515550) /13.8kV (515551) XFMR CKT 1, near MNCWND37 345kV. a. Apply fault at the MNCWND37 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer. **Trip generator MNCWNDG1 (515921).**
FLT9012-PO1	P6	**Prior Outage of MINCO 7 (514801) to GRACMNT7 (515800) 345 kV line circuit 1;** 3 phase fault on the CIMARON2 345 kV (514901) /138 kV (514898) /13.8kV (515715) XFMR CKT 1, near CIMARON7 345kV. a. Apply fault at the CIMARON7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9013-PO1	P6	**Prior Outage of MINCO 7 (514801) to GRACMNT7 (515800) 345 kV line circuit 1;** 3 phase fault on the CIMARON7 (514901) to MATHWSN7 (515497) 345 kV line circuit 1, near CIMARON7. a. Apply fault at the CIMARON7 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.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9014-PO1	P6	**Prior Outage of MINCO 7 (514801) to GRACMNT7 (515800) 345 kV line circuit 1;** 3 phase fault on the CIMARON7 (514901) to NORTWST7 (514880) 345 kV line circuit 1, near CIMARON7. a. Apply fault at the CIMARON7 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.
FLT9015-PO1	P6	**Prior Outage of MINCO 7 (514801) to GRACMNT7 (515800) 345 kV line circuit 1;** 3 phase fault on the CIMARON7 (514901) to FSHRTAP7 (515610) 345 kV line circuit 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator CANADNG1 (515900).** **Trip generator CANADNG2 (515902).** **Trip generator KNGFSHR-GEN1 (515664).** **Trip generator KNGFSHR-GEN2 (515665).** 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.
FLT9016-PO1	P6	**Prior Outage of MINCO 7 (514801) to GRACMNT7 (515800) 345 kV line circuit 1;** 3 phase fault on the CIMARON7 (514901) to DRAPER 7 (514934) 345 kV line circuit 1, near CIMARON7. a. Apply fault at the CIMARON7 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.
FLT9003-PO2	P6	**Prior Outage of MINCO 7 (514801) to CIMARON7 (514901) 345 kV line circuit 1;** 3 phase fault on the GRACMNT7 (515800) to GEN-2015-093 (563269) 345 kV line circuit 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G15-093-GEN1 (563272).** **Trip generator G15-093-GEN2 (563273).** 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.
FLT9004-PO2	P6	**Prior Outage of MINCO 7 (514801) to CIMARON7 (514901) 345 kV line circuit 1;** 3 phase fault on the GRACMNT7 (515800) to G16-037-TAP (560078) 345 kV line circuit 1, near GRACMNT7. a. Apply fault at the GRACMNT7 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.
FLT9005-PO2	P6	**Prior Outage of MINCO 7 (514801) to CIMARON7 (514901) 345 kV line circuit 1;** 3 phase fault on the GRACMNT7 (515800) to G16-091-TAP (587744) 345 kV line circuit 1, near GRACMNT7. a. Apply fault at the GRACMNT7 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.
FLT9011-PO2	P6	**Prior Outage of MINCO 7 (514801) to CIMARON7 (514901) 345 kV line circuit 1;** 3 phase fault on the GRACMNT3 345 kV (515800) /230 kV (515802) /13.8kV (515801) XFMR CKT 1, near GRACMNT7 345kV. a. Apply fault at the GRACMNT7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT1001-SB	P4	**Stuck Breaker on at MINCO 7 (514801) at 345kV** a. Apply single-phase fault at MINCO 7 (514801) on the 345kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the MINCO 7 (514801) to GRACMNT7 (515800) 345kV line CKT 1. d. Trip the MINCO 7 (514801) to MNCWND37 (515549) 345kV line CKT 1. **Trip generator G15-057-GEN1 (584953).** **Trip generator G15-057-GEN2 (584954).** **Trip generator G15-057-GEN3 (584955).** **Trip generator MNCO4G11 (515943).** **Trip generator G14-056-GEN2 (584064).** **Trip generator G14-056-GEN3 (584067).** **Trip generator G11-010_G14-005 (599117, 515551, 599119, 599120).**

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT1002-SB	P4	**Stuck Breaker on at MINCO 7 (514801) at 345kV** a. Apply single-phase fault at MINCO 7 (514801) on the 345kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the MINCO 7 (514801) to GRACMNT7 (515800) 345kV line CKT 1. d. Trip the MINCO 7 (514801) to MCNOWND7 (515444) 345kV line CKT 1. **Trip generator MNCOWNG (515907).** **Trip generator MNCOWNG (515445).** **Trip generator MNCOWNG (515439).**
FLT1003-SB	P4	**Stuck Breaker on at MINCO 7 (514801) at 345kV** a. Apply single-phase fault at MINCO 7 (514801) on the 345kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the MINCO 7 (514801) to CIMARON7 (514901) 345kV line CKT 1. d. Trip the MINCO 7 (514801) to MNCWND37 (515549) 345kV line CKT 1. **Trip generator G15-057-GEN1 (584953).** **Trip generator G15-057-GEN2 (584954).** **Trip generator G15-057-GEN3 (584955).** **Trip generator MNCO4G11 (515943).** **Trip generator G14-056-GEN2 (584064).** **Trip generator G14-056-GEN3 (584067).** **Trip generator G11-010_G14-005 (599117, 515551, 599119, 599120).**
FLT1004-SB	P4	**Stuck Breaker on at MINCO 7 (514801) at 345kV** a. Apply single-phase fault at MINCO 7 (514801) on the 345kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the MINCO 7 (514801) to CIMARON7 (514901) 345kV line CKT 1. d .Trip the MINCO 7 (514801) to MCNOWND7 (515444) 345kV line CKT 1. **Trip generator MNCOWNG (515907).** **Trip generator MNCOWNG (515445).** **Trip generator MNCOWNG (515439).**
FLT1005-SB	P4	**Stuck Breaker on at GRACMNT7 (515800) at 345kV** a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the GRACMNT7 (515800) to MINCO 7 (514801) 345kV line CKT 1. d. Trip the GRACMNT7 (515800) to GEN-2015-093 (563269) 345kV line CKT 1. **Trip generator G15-093-GEN1 (563272).** **Trip generator G15-093-GEN2 (563273).**
FLT1006-SB	P4	**Stuck Breaker on at GRACMNT7 (515800) at 345kV** a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the GRACMNT3 138/345/13.8kV (515802 /515800 /515801) transformer CKT 1. d. Trip the GRACMNT7 (515800) to G16-091-TAP (587744) 345kV line CKT 1.
FLT1007-SB	P4	**Stuck Breaker on at GRACMNT7 (515800) at 345kV** a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the GRACMNT7 (515800) to G16-037-TAP (560078) 345kV line CKT 1. d. Trip the GRACMNT3 138/345/13.8kV (515802 /515800 /515801) transformer CKT 1.
FLT1008-SB	P4	**Stuck Breaker on at GRACMNT7 (515800) at 345kV** a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the GRACMNT7 (515800) to MINCO 7 (514801) 345kV line CKT 1. d. Trip the GRACMNT7 (515800) to G16-037-TAP (560078) 345kV line CKT 1.
FLT1009-SB	P4	**Stuck Breaker on at GRACMNT7 (515800) at 345kV** a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the GRACMNT7 (515800) to G16-091-TAP (587744) 345kV line CKT 1. d. Trip the GRACMNT7 (515800) to GEN-2015-093 (563269) 345kV line CKT 1. **Trip generator G15-093-GEN1 (563272).** **Trip generator G15-093-GEN2 (563273).**

6.3 Results

Table 6-2 shows the results of the fault events simulated for each of the four modified cases. The associated stability plots are provided in Appendix D.

Table 6-2: GEN-2007-043 & GEN-2016-131 Dynamic Stability Results

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT45-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable(2)
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable(2)
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable(2)
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable(2)
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable(2)
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable(2)
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable(2)
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable(2)
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable(2)
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9029-3PH	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9030-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT01-SB	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable(2)
FLT02-SB	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable(2)
FLT03-SB	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable(2)
FLT04-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable(2)
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-PO1	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable(2)
FLT9013-PO1	Pass	Pass	Stable	Pass	Pass	Stable(1)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

(1) REDBUD units (514899, 514900, 514905, 514910, 514940, 514942) had EFD oscillations in the 21LL case with and without the modification included

(2) Spring Creek units (514882, 514883) had EFD oscillations in the 28SP case with and without the modification included

During many of the faults studied in the 21LL case the REDBUD units (514899, 514900, 514905, 514910, 514940, 514942) showed EFD oscillations. This was observed in both the DISIS and modification cases, so it was not attributed to the GEN-2007-043 and GEN-2016-131 project.

Figure 6-1 shows the REDBUD EFD oscillation during FLT9002-3PH in the 21LL Modification case. This problem was also present in the existing DISIS-2017-001 21LL case as shown in Figure 6-2.

Figure 6-1: FLT9002-3PH REDBUD Units EFD Oscillations (21LL Modification Case)

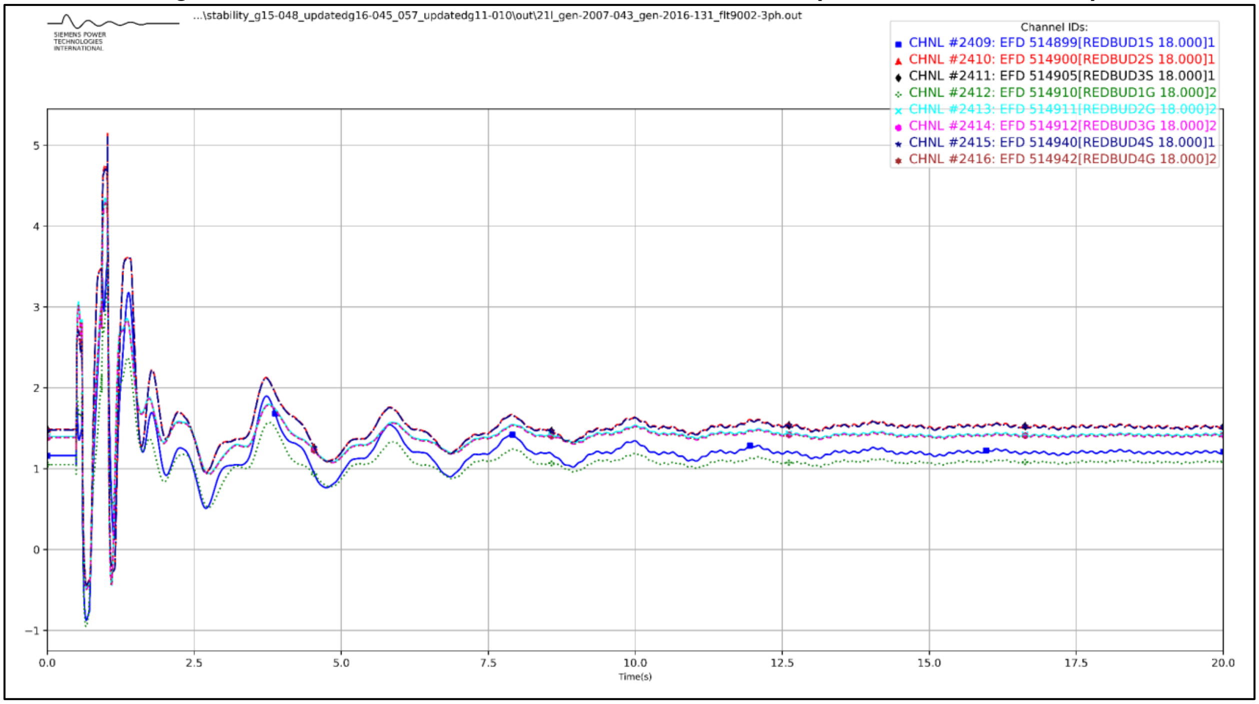
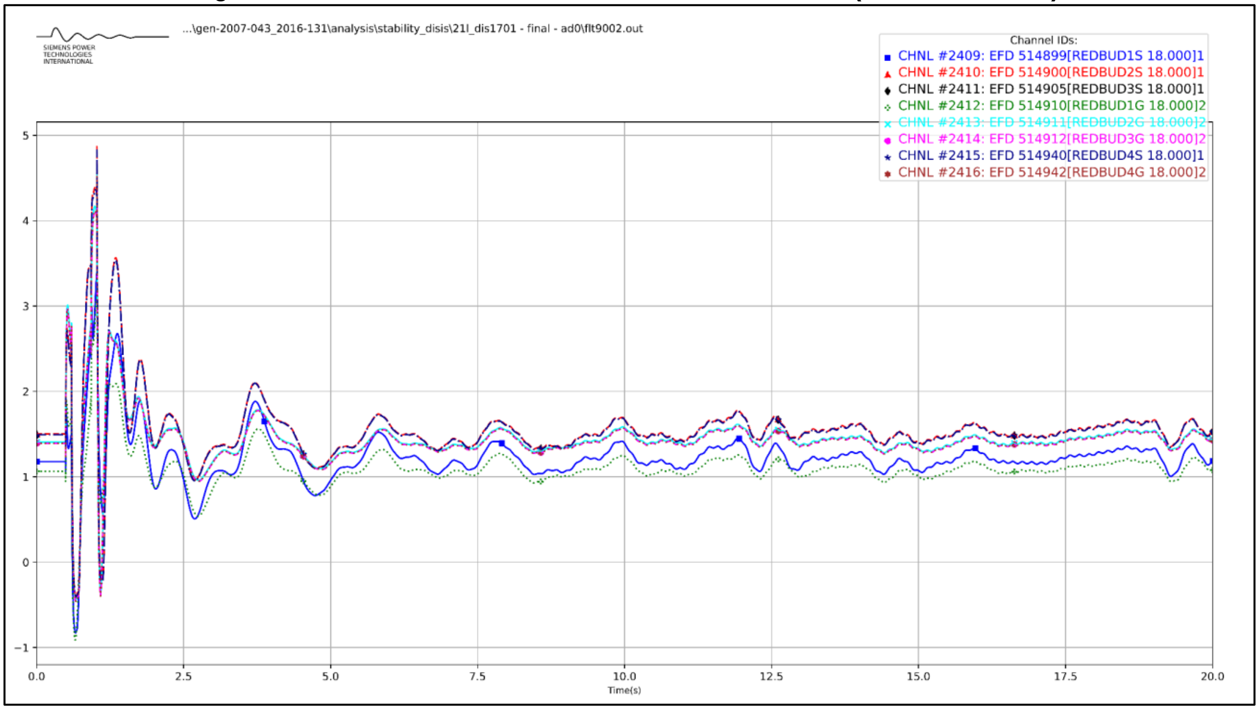


Figure 6-2: FLT9002-3PH REDBUD Units EFD Oscillations (21LL DISIS Case)



During many of the faults studied in the 28SP case the Spring Creek units (514882, 514883) showed EFD oscillations. This was observed in both the DISIS and modification cases, so it was not attributed to the GEN-2007-043 and GEN-2016-131 project. Figure 6-3 shows the Spring Creek EFD oscillation during FLT9001-3PH in the 28SP Modification case. This problem was also present in the existing DISIS-2017-001 28SP case as shown in Figure 6-4.

Figure 6-3: FLT9001-3PH Spring Creek Units EFD Oscillations (28SP Modification Case)

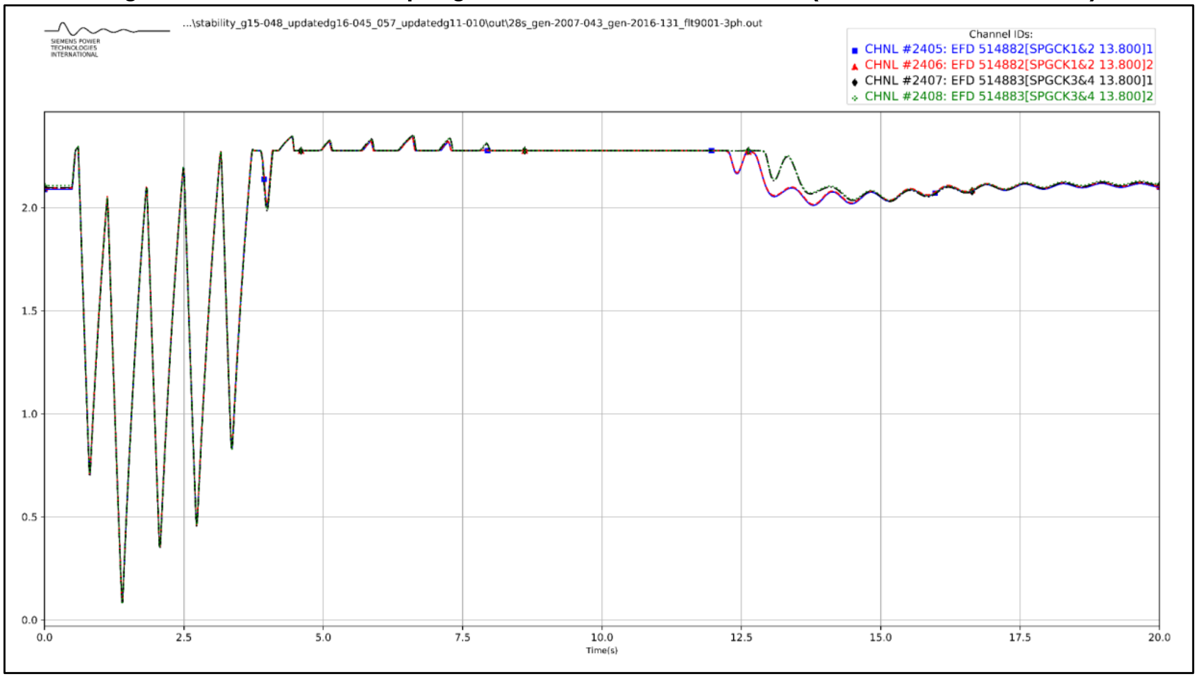
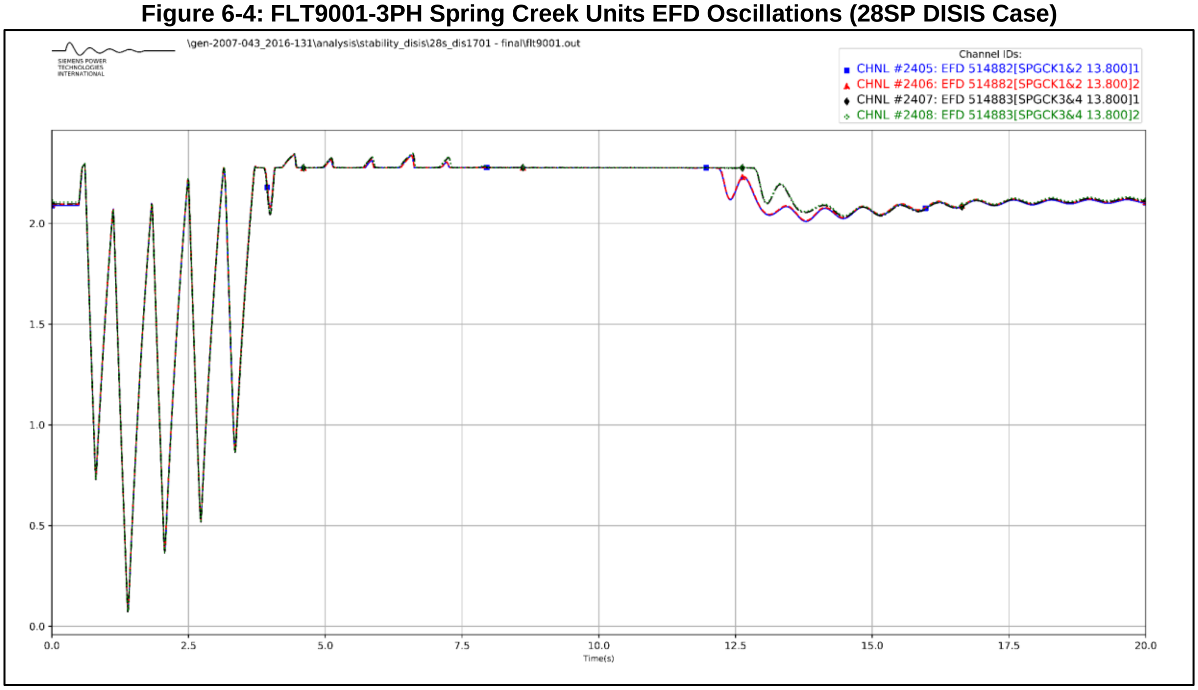


Figure 6-4: FLT9001-3PH Spring Creek Units EFD Oscillations (28SP DISIS Case)



There were no damping or voltage recovery violations attributed to the GEN-2007-043 and GEN-2016-131 project 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.

7.0 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 which is 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.

7.1 Results

The modified generating capacity of GEN-2007-043 and GEN-2016-131 (203.9 MW) exceeds the GIA Interconnection Service amount, (202.5 MW), as listed in Appendix A.

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.

8.0 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.

8.1 Results

SPP determined the requested modification is not a Material Modification based on the results of this Modification Request Impact Study performed by Aneden. Aneden evaluated the impact of the requested modification on the prior study results. Aneden determined that the requested modification resulted in similar dynamic stability and short circuit analyses and that the prior study power flow results are not negatively impacted.

This determination implies that any network upgrades already required by GEN-2007-043 and GEN-2016-131 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.

9.0 Conclusions

The Interconnection Customer for GEN-2007-043 and GEN-2016-131 requested a Modification Request Impact Study to assess the impact of the turbine and facility changes to the Minco II turbine configuration to 61 x GE 1.62 MW + 2 x GE 2.32 MW while keeping the Minco I configuration of 62 x GE 1.62 MW consistent for a total combined capacity of 203.9 MW. The combined generating capacity of GEN-2007-043 and GEN-2016-131 (203.9) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 202.5 MW, as listed in Appendix A. 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. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

In addition, the modification request included changes to the collection system and generator step-up transformers.

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.81% compared to the DISIS-2017-001 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, GE, the change in stability model from GEWTG2 to REGCAU1, project capacity increase, and the use of a PPC required short circuit and dynamic stability analyses.

Aneden reviewed the GIRs that shared the same POI, Minco 345 kV, and updated as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the GEN-2011-010 and GEN-2014-005 project configurations in the base models. All analyses were performed using the PTI PSS/E version 33 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak models showed that the GEN-2007-043 and GEN-2016-131 project needed 12.9 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 13.8 MVAr found for the existing GEN-2007-043 and GEN-2016-131 configuration calculated using the DISIS-2017-001 models. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind 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 results from the short circuit analysis with the updated topology showed that the maximum GEN-2007-043 and GEN-2016-131 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2007-043 and GEN-2016-131 POI was not greater than 0.92 kA for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2007-043 and GEN-2016-131 generators online were below 46 kA for the 2021SP and 2028SP models.

The dynamic stability analysis was performed using the four modified study models, 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak. Up to 53 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

The results of the dynamic stability analysis showed that there were numerous existing base case issues that were mitigated prior to studying the modification request. Several case adjustments were made including updating the GEN-2015-048, GEN-2016-045, and GEN-2016-057 configurations were updated with the latest project configurations in the base models in order to avoid base case stability issues. In addition, there were two other types of existing stability oscillations. First, EFD oscillations were found for many faults studied in the 21LL case from the REDBUD units (514899, 514900, 514905, 514910, 514940, 514942). Second, EFD oscillations were found for many faults studied in the 28SP case from the Spring Creek units (514882, 514883). These issues were observed in the DISIS and modification cases so they were not attributed to the GEN-2007-043 and GEN-2016-131 modification.

There were no damping or voltage recovery violations attributed to the GEN-2007-043 and GEN-2016-131 project 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.