Submitted to
Southwest Power Pool

SPP Southwest Power Pool

Report On

GEN-2011-010 and GEN-2014-005 Modification Request Impact Study

Revision R1

Date of Submittal
June 18, 2021

anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
06/18/2021	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-2011-010 and GEN-2014-005, two active Generation Interconnection Requests (GIR) with a point of interconnection (POI) at the Minco 345 kV Substation.

The GEN-2011-010 and GEN-2014-005 projects are proposed to interconnect in the Oklahoma Gas & Electric Company (OKGE) control area with a combined capacity of 106.5 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2011-010 and GEN-2014-005 to change the turbine configuration to 17 x GE 1.69 MW + 42 x GE 1.85 MW + 1 x GE 1.85 MW + 3 x GE 2.3 MW for a total generating capacity of 115.18 MW. The generating capacity for GEN-2011-010 and GEN-2014-005 (115.18 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, 106.5 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 includes the use of a Power Plant Controller (PPC) to limit the power injected into the POI.

In addition, the modification request included changes to the collection system, generator step-up transformers, and main substation transformer. The existing and modified configurations for GEN-2011-010 and GEN-2014-005 are shown in Table ES-2.

Table ES-1: GEN-2011-010 & GEN-2014-005 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2011-010	Minco 345 kV (514801)	63 x GE 1.69 MW = 106.47 MW	100.8
GEN-2014-005	Minco 345 kV (514801)		5.7
		Total Combined Capacity	106.5

Table ES-2: GEN-2011-010 & GEN-2014-005 Modification Request

Facility	Existing	Modification			
Point of Interconnection	Minco 345 kV (514801)	Minco 345 kV (514801)			
Configuration/Capacity	63 x GE 1.69 MW = 106.47 MW	17 x GE 1.69 MW + 42 x GE 1.85 MW + 1 x GE 1.85 MW + 3 x GE 2.3 MW = 115.18 MW PPC to limit POI Injection to 106.5 MW			
Generation Interconnection Line	<u>Line shared with GEN-2015-057</u> Length = 10.4 miles R = 0.000560 pu X = 0.005090 pu B = 0.090600 pu	<u>Line shared with GEN-2015-057</u> Length = 10.4 miles R = 0.000560 pu X = 0.005090 pu B = 0.090600 pu			
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 Rating MVA = 225 MVA, Winding 2 Rating MVA = 225 MVA, Winding 3 Rating MVA = 75 MVA	X = 7.998%, R = 0.199%, Winding MVA = 102 MVA, Rating MVA = 170 MVA			
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 63: X = 5.7%, R = 0.76%, Winding MVA= 126 MVA, Rating MVA = 126 MVA	Gen 1 Equivalent Qty: 17: X = 5.705%, R = 0.792%, Winding MVA= 30.6 MVA, Rating MVA = 34 MVA	Gen 2 Equivalent Qty: 42: X = 5.699%, R = 0.759%, Winding MVA = 86.352 MVA, Rating MVA[2] = 86.4 MVA	Gen 3 Equivalent Qty: 1: X = 5.699%, R = 0.759%, Winding MVA = 2.3 MVA, Rating MVA = 2.3 MVA	Gen 4 Equivalent Qty: 3: X = 5.699%, R = 0.759%, Winding MVA = 8.031 MVA, Rating MVA[2] = 8.0 MVA
Equivalent Collector Line[3]	R = 0.000460 pu X = 0.000340 pu B = 0.066910 pu	R = 0.009294 pu X = 0.011713 pu B = 0.056157 pu			

1) X/R based on Winding MVA, 2) Rating rounded up 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 2.89% compared to the recently studied DISIS-2017-001 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, GE, short circuit and dynamic stability analyses were required because of the project capacity increase and the use of a PPC.

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-2016-002 Group 1 study models:

1. 2017 Winter Peak (2017WP),
2. 2018 Summer Peak (2018SP),
3. 2026 Summer Peak (2026SP)

Aneden updated the GIRs that had POIs within 3 buses of the GEN-2011-010 and GEN-2014-005 POI as applicable based on SPP's confirmation of the latest project configurations. Modeling updates for GEN-2007-043, GEN-2014-056, GEN-2015-057, GEN-2015-063, GEN-2016-037, GEN-2016-045, GEN-2016-057, and GEN-2016-131 were included in the base models. All analyses were performed using the PTI PSS/E version 33.7 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak models showed that the GEN-2011-010 and GEN-2014-005 project needed 14.74 MVAr of reactor shunts on the 34.5 kV bus of the project substation, a decrease from the 15.8 MVAr found for the existing GEN-2011-010 and GEN-2014-005 configuration. 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-2011-010 and GEN-2014-005 contribution to three-phase fault currents in the immediate systems at or near GEN-2011-010 and GEN-2014-005 was not greater than 0.57 kA for the 2018SP and 2026SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2011-010 and GEN-2014-005 generators online were below 45 kA for the 2018SP and 2026SP models.

The dynamic stability analysis was performed using the three modified study models, 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak. Up to 65 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

The results of the dynamic stability analysis showed that there were no damping or voltage recovery violations 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-2011-010 and GEN-2014-005. 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 33.7 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 most recently studied 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 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-2011-010 and GEN-2014-005 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-2011-010 and GEN-2014-005 are active Interconnection Requests with queue statuses of "IA FULLY EXECUTED/COMMERCIAL OPERATION." Both GEN-2011-010 and GEN-2014-005 are wind farms, and have maximum summer and winter queue capacities of 100.8 MW and 5.7 MW respectively with Energy Resource Interconnection Service (ERIS).

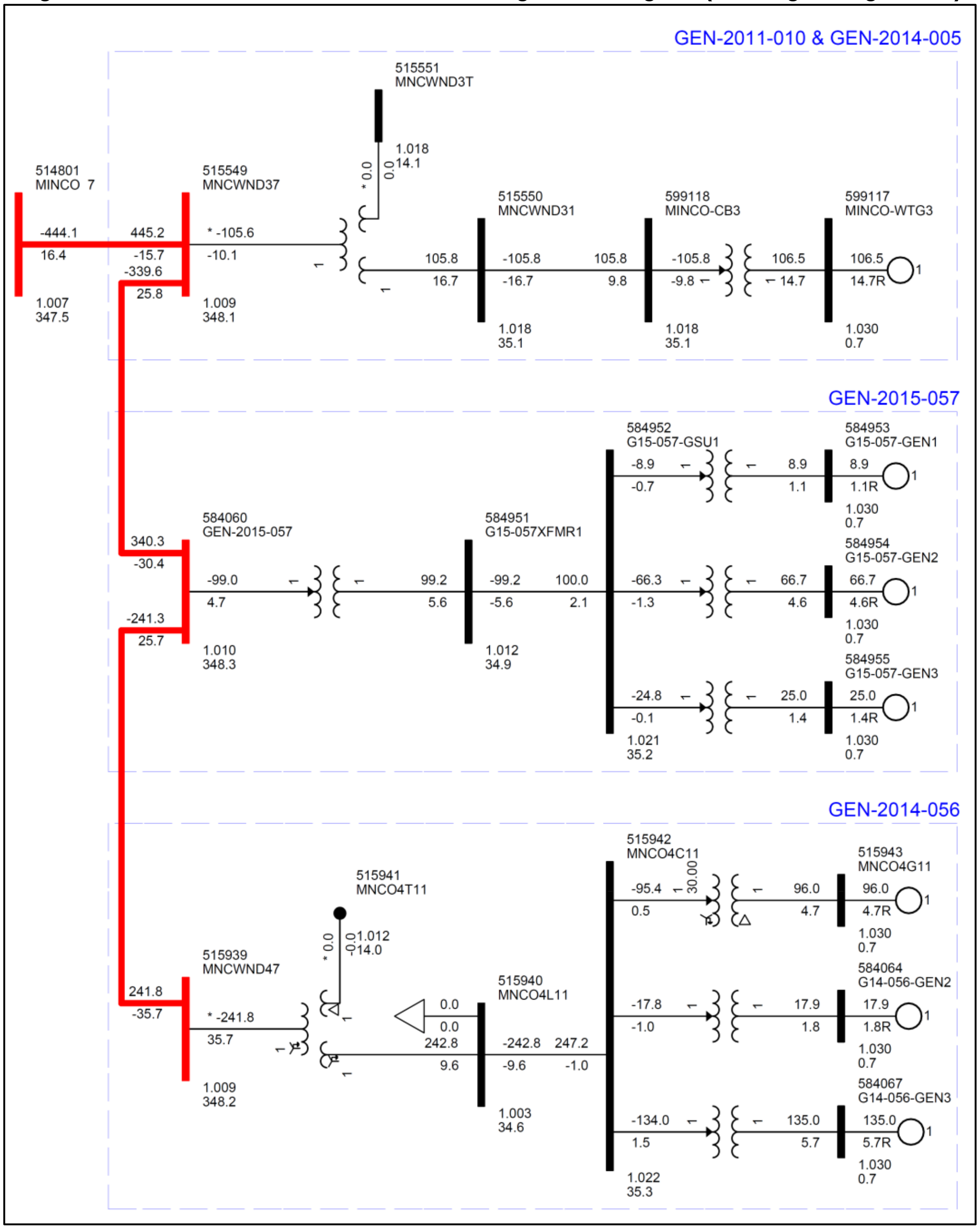
The GEN-2011-010 and GEN-2014-005 projects were originally studied as part of Group 1 in the DISIS-2011-001 and DISIS-2014-001 studies respectively. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2011-010 and GEN-2014-005 configuration.

The GEN-2011-010 and GEN-2014-005 projects are proposed to interconnect in the Oklahoma Gas & Electric Company (OKGE) control area with a combined capacity of 106.5 MW as shown in Table 2-1 below.

Table 2-1: GEN-2011-010 & GEN-2014-005 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2011-010	Minco 345 kV (514801)	63 x GE 1.69 MW = 106.47 MW	100.8
GEN-2014-005	Minco 345 kV (514801)		5.7
		Total Combined Capacity	106.5

Figure 2-1: GEN-2011-010 & GEN-2014-005 Single Line Diagram (Existing Configuration)



This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2011-010 and GEN-2014-005 to change the turbine configuration to 17 x GE 1.69 MW + 42 x GE 1.85 MW + 1 x GE 1.85 MW + 3 x GE 2.3 MW for a total generating capacity of 115.18 MW. The requested modification includes the use of a Power Plant Controller (PPC) to limit the power injected into the POI. In addition, the modification request included changes to the collection system, generator step-up transformers, and main substation transformer. Figure 2-2 shows the power flow model single line diagram for the GEN-2011-010 and GEN-2014-005 modification. The existing and modified configurations for GEN-2011-010 and GEN-2014-005 are shown in Table 2-2.

The modified generating capacity of GEN-2011-010 and GEN-2014-005 (115.18 MW) exceeds the GIA Interconnection Service amount, 106.5 MW.

Figure 2-2: GEN-2011-010 & GEN-2014-005 Single Line Diagram (Modification Configuration)

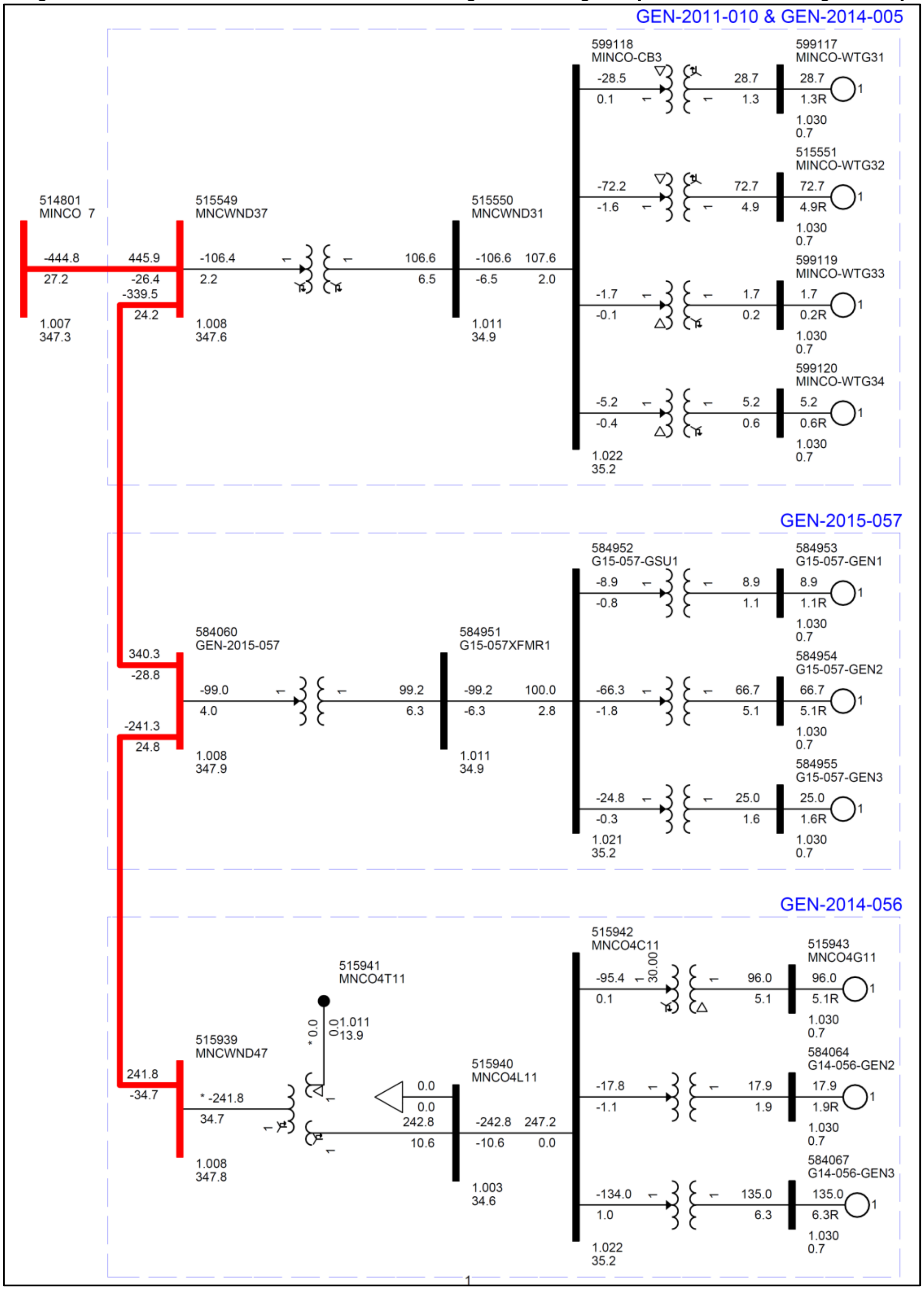


Table 2-2: GEN-2011-010 & GEN-2014-005 Modification Request

<table>
<tr><th>Facility</th><th>Existing</th><th colspan="4">Modification</th></tr>
<tr><td>Point of Interconnection</td><td>Minco 345 kV (514801)</td><td colspan="4">Minco 345 kV (514801)</td></tr>
<tr><td>Configuration/Capacity</td><td>63 x GE 1.69 MW = 106.47 MW</td><td colspan="4">17 x GE 1.69 MW + 42 x GE 1.85 MW + 1 x GE 1.85 MW + 3 x GE 2.3 MW = 115.18 MW
PPC to limit POI Injection to 106.5 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td><u>Line shared with GEN-2015-057</u>
Length = 10.4 miles
R = 0.000560 pu
X = 0.005090 pu
B = 0.090600 pu</td><td colspan="4"><u>Line shared with GEN-2015-057</u>
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<tr><td>Main Substation Transformer[1]</td><td>X12 = 7.969% R12 = 0.139%, X23 = 2.1% R23 = 0.0%, X13 = 11.5% R13 = 0.0%, Winding MVA = 135 MVA, Winding 1 Rating MVA = 225 MVA, Winding 2 Rating MVA = 225 MVA, Winding 3 Rating MVA = 75 MVA</td><td colspan="4">X = 7.998%, R = 0.199%,
Winding MVA = 102 MVA,
Rating MVA = 170 MVA</td></tr>
<tr><td>Equivalent GSU Transformer[1]</td><td>Gen 1 Equivalent Qty: 63:
X = 5.7%, R = 0.76%,
Winding MVA= 126 MVA,
Rating MVA = 126 MVA</td><td>Gen 1 Equivalent Qty: 17:
X = 5.705%, R = 0.792%, Winding MVA= 30.6 MVA, Rating MVA = 34 MVA</td><td>Gen 2 Equivalent Qty: 42:
X = 5.699%, R = 0.759%, Winding MVA = 86.352 MVA, Rating MVA[2] = 86.4 MVA</td><td>Gen 3 Equivalent Qty: 1:
X = 5.699%, R = 0.759%, Winding MVA = 2.3 MVA, Rating MVA = 2.3 MVA</td><td>Gen 4 Equivalent Qty: 3:
X = 5.699%, R = 0.759%, Winding MVA = 8.031 MVA, Rating MVA[2] = 8.0 MVA</td></tr>
<tr><td>Equivalent Collector Line[3]</td><td>R = 0.000460 pu
X = 0.000340 pu
B = 0.066910 pu</td><td colspan="4">R = 0.009294 pu
X = 0.011713 pu
B = 0.056157 pu</td></tr>
</table>

1) X/R based on Winding MVA, 2) Rating rounded up 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-2016-002 Group 1 study models. Aneden updated the GIRs that had POIs within 3 buses of the GEN-2011-010 and GEN-2014-005 POI as applicable based on SPP's confirmation of the latest project configurations. Modeling updates for GEN-2007-043, GEN-2014-056, GEN-2015-057, GEN-2015-063, GEN-2016-037, GEN-2016-045, GEN-2016-057, and GEN-2016-131 were included in the base models.

The methodology and results of the comparisons are described below. The analysis was completed using PSS/E version 33.7 software.

3.1 POI Injection Comparison

The real power injection at the POI was determined using PSS/E to compare the most recently studied DISIS-2017-001 power flow configuration and the requested modifications with the PPC in place for GEN-2011-010 and GEN-2014-005. 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 2.89%) 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. The MW shown include injections from both the GEN-2011-010 and GEN-2014-005 project and nearby projects GEN-2015-057 and GEN-2014-056 which share the gen-tie line with GEN-2011-010 and GEN-2014-005.

Table 3-1: GEN-2011-010 & GEN-2014-005 POI Injection Comparison

Interconnection Request	DISIS-2017-001 Powerflow POI Injection from Combined Projects (MW)	MRIS POI Injection from Combined Projects w/ PPC (MW)	POI Injection Difference from Combined Projects %
GEN-2011-010 & GEN-2014-005	432.4*	444.9*	2.89%

*This total MW amount includes the GEN-2015-057 and GEN-2014-056 projects which share the gen-tie line

3.2 Turbine Parameters Comparison

SPP determined that while the modification used the same turbine manufacturer, GE, the increase in the project capacity and the use of the PPC caused the need for short circuit and dynamic stability analyses as the 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.

3.3 Equivalent Impedance Comparison Calculation

Since 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-2011-010 and GEN-2014-005 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 nearby projects GEN-2015-057 and GEN-2014-056 were switched offline and disconnected for this analysis as they share a gen-tie line with GEN-2011-010 and GEN-2014-005. The GEN-2011-010 and GEN-2014-005 generators were then 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-2011-010 and GEN-2014-005 project needed approximately 14.74 MVAr of compensation at its project substation, to reduce the POI MVAr to zero. This is a decrease from the 15.8 MVAr found for the existing GEN-2011-010 and GEN-2014-005 configuration. 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-2011-010 and GEN-2014-005 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)		
			17WP	18SP	26SP
GEN-2011-010 & GEN-2014-005	514801	Minco 345 kV	14.74	14.74	14.74

Figure 4-1: GEN-2011-010 & GEN-2014-005 Single Line Diagram (Existing Shunt Reactor)

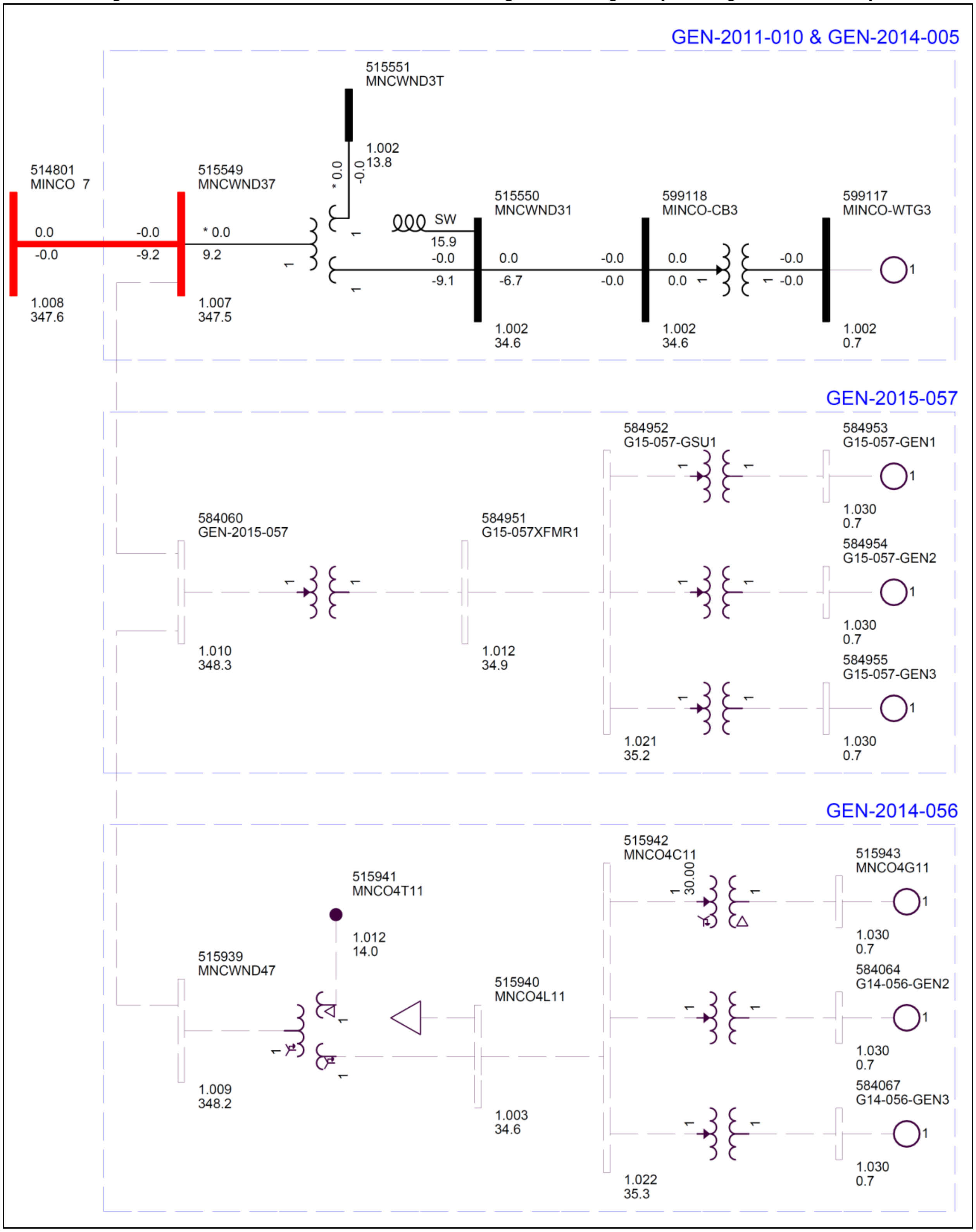
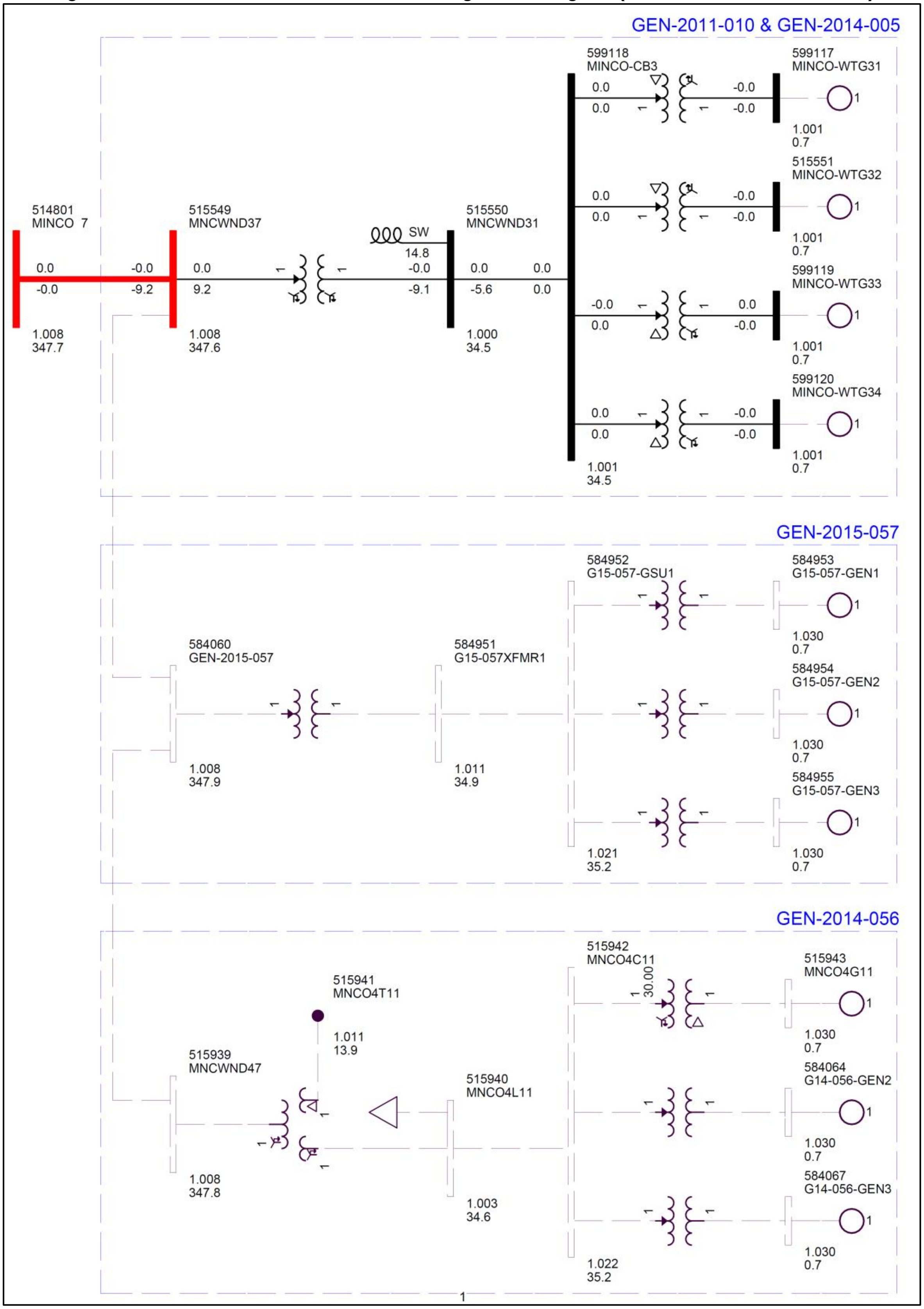


Figure 4-2: GEN-2011-010 & GEN-2014-005 Single Line Diagram (Modification Shunt Reactor)



5.0 Short Circuit Analysis

A short circuit study was performed using the 2018SP and 2026SP models for GEN-2011-010 and GEN-2014-005. 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 with and without GEN-2011-010 and GEN-2014-005 online.

5.2 Results

The results of the short circuit analysis for the 2018SP and 2026SP models are summarized in Table 5-1 through Table 5-3 respectively. The GEN-2011-010 and GEN-2014-005 POI bus fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 17.42 kA with the GEN-2011-010 and GEN-2014-005 project online.

The maximum fault current calculated within 5 buses of the GEN-2011-010 and GEN-2014-005 POI was less than 45 kA for the 2018SP and 2026SP models respectively. The maximum GEN-2011-010 and GEN-2014-005 contribution to three-phase fault current was about 5.0% and 0.57 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2018SP	16.80	17.34	0.54	3.2%
2026SP	16.88	17.42	0.54	3.2%

Table 5-2: 2018SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	16.5	0.00	0.0%
138	44.6	0.08	0.2%
230	8.2	0.01	0.1%
345	32.6	0.57	5.0%
Max	**44.6**	**0.57**	**5.0%**

Table 5-3: 2026SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	16.5	0.00	0.0%
138	44.3	0.08	0.2%
230	8.2	0.01	0.1%
345	32.6	0.57	5.0%
Max	**44.3**	**0.57**	**5.0%**

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-2011-010 and GEN-2014-005 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-2011-010 and GEN-2014-005 configuration of 17 x GE 1.69 MW (REGCAU1) + 42 x GE 1.85 MW (REGCAU1) + 1 x GE 1.85 MW (REGCAU1) + 3 x GE 2.3 MW (REGCAU1). The requested modification included the use of a PPC (REPCTAU1) to limit the power injected into the POI to below the GIA amount. This stability analysis was performed using PTI's PSS/E version 33.7 software.

The stability models were developed using the DISIS-2016-002 Group 1 models. The modifications requested for the GEN-2011-010 and GEN-2014-005 projects were used to create modified stability models for this impact study. Aneden updated the GIRs that had POIs within 3 buses of the GEN-2011-010 and GEN-2014-005 POI as applicable based on SPP's confirmation of the latest project configurations. Modeling updates for GEN-2007-043, GEN-2014-056, GEN-2015-057, GEN-2015-63, GEN-2016-037, GEN-2016-045, GEN-2016-057, and GEN-2016-131 were included in the base models.

GEN-2015-084 is a withdrawn project that exists in the DISIS-2016-002 Group 1 models. In order to maintain the dispatch of the models as previously studied, SPP instructed Aneden to disable the tripping relays without removing the generator to prevent the generator from tripping during some faults.

In addition, the following system adjustments were made to address existing base case issues that are not attributed to the modification request:

1. GEN-2015-048 Qgen was changed from 0 MVAr to 20 MVAr
2. GEN-2015-071 GSU was changed from 1.0 to 1.05

The modified dynamics model data for the GEN-2011-010 and GEN-2014-005 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-2011-010 and GEN-2014-005 and other equally and prior queued projects in Group 1. In addition, voltages of five (5) buses away from the POI of GEN-2011-010 and GEN-2014-005 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), 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-2011-010 and GEN-2014-005 and selected additional fault events for GEN-2011-010 and GEN-2014-005 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 faults with stuck breakers. The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 2017 Winter Peak, 2018 Summer Peak, and the 2026 Summer Peak models.

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT01-3PH	P1	3 phase fault on CIMARON7 345 kV (514901) to MATHWSN7 345 kV (515497) line CKT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT02-3PH	P1	3 phase fault on CIMARON7 345 kV (514901) to NORTWST7 345 kV (514880) line CKT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT03-3PH	P1	3 phase fault on CIMARON7 345 kV (514901) to MINCO 7 345 kV (514801) line CKT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT04-3PH	P1	3 phase fault on CIMARON7 345 kV (514901) to DRAPER 7 345 kV (514934) line CKT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT05-3PH	P1	3 phase fault on the CIMARON7 345 kV (514901) to CIMARON4 138 kV (514898) to CIMARO11 13.8 kV (515714) XFMR CKT 1, near CIMARON7 345 kV. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT65-3PH	P1	3 phase fault on MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) line CKT 1, near MATHWSN7. a. Apply fault at the MATHWSN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT67-3PH	P1	3 phase fault on MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line CKT 1,near MATHWSN7. a. Apply fault at the MATHWSN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT68-3PH	P1	3 phase fault on NORTWST7 345 kV (514880) to NORTWST4 138 kV (514879) to NORTWS41 13.8 kV (514885) XFMR CKT 1, near NORTWST7 345 kV. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT69-3PH	P1	3 phase fault on NORTWST7 345 kV (514880) to ARCADIA7 345 kV (514908) line CKT 1, near NORTWST7. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT70-3PH	P1	3 phase fault on NORTWST7 345 kV (514880) to SPRNGCK7 345 kV (514881) line CKT 1, near NORTWST7. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT75-3PH	P1	3 phase fault on MATHWSN7 345 kV (515497) to CIMARON7 (514901) 345 kV line CKT 1, near MATHWSN7. a. Apply fault at the MATHWSN7 345 kV bus. b. Clear fault after 5 cycle and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT04-PO1	P6	**Prior Outage of CIMARON7 (514901) to NORTWST7 (514880) line CKT 1;** 3 phase fault on CIMARON7 345 kV (514901) to DRAPER 7 345 kV (514934) line CKT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT05-PO2	P6	**Prior Outage of CIMARON7 (514901) to MINCO 7 (514801) line CKT 1;** 3 phase fault on the CIMARON7 345 kV (514901) to CIMARON4 138 kV (514898) to CIMARO11 13.8 kV (515714) XFMR CKT 1, near CIMARON7 345 kV. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT75-PO3	P6	**Prior Outage of MATHWSN7 (515497) to NORTWST7 (514880) line CKT 1;** 3 phase fault on MATHWSN7 (515497) - CIMARON7 (514901), CKT 1 near MATHWSN7. a. Apply fault at the MATHWSN7 bus. b. Clear fault after 5 cycles and trip the faulted line.
FLT20-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 1 d. CIMARON7 345 kV (514901) / CIMARON4 138 kV (514898) / CIMARON11 13.8 kV (515714) transformer CKT 1.
FLT9001-3PH	P1	3 phase fault on CIMARON7 345 kV (514901) to FSHRTAP7 345 kV (515610) line CKT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generators CANDIAN_WTG1 (599114), CANDIAN_WTG2 (599116).** **Trip generators KNGFSHR-GEN1 (599122), KNGFSHR-GEN2 (599124).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on DRAPER 7 345 kV (514934) to SEMINOL7 345 kV (515045) line CKT 1, near DRAPER 7. a. Apply fault at the DRAPER 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1	3 phase fault on the DRAPER 7 345 kV (514934) to DRAPER 4 138 kV (514933) to DRAPER 21 13.8 kV (515792) XFMR CKT 1, near DRAPER 7 345 kV. a. Apply fault at the DRAPER 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9004-3PH	P1	3 phase fault on FSHRTAP7 345 kV (515610) to CANADN7 345 kV (515605) line CKT 1, near FSHRTAP7. a. Apply fault at the FSHRTAP7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generators CANDIAN_WTG1 (599114), CANDIAN_WTG2 (599116).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on FSHRTAP7 345 kV (515610) to KNGFSHR7 345 kV (515600) line CKT 1, near FSHRTAP7. a. Apply fault at the FSHRTAP7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generators KNGFSHR-GEN1 (599122), KNGFSHR-GEN2 (599124).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9006-3PH	P1	3 phase fault on MATHWSN7 345 kV (515497) to TRAWERSE3 (900001) 345 kV line CKT 1, near MATHWSN7. a. Apply fault at the MATHWSN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator G16-045_G16-057 (587300, 587303, 587307, 587380, 587383, 587387).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9007-3PH	P1	3 phase fault on MNCWND37 345 kV (515549) to GEN-2015-057 345 kV (584060) line CKT 1, near MNCWND37. a. Apply fault at the MNCWND37 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generators G15-057-GEN (584953) (584954) (584955).** **Trip generators G14-056-GEN (515943) (584064) (584067).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.D44
FLT9010-3PH	P1	3 phase fault on MATHWSN7 345 kV (515497) to REDNGTN7 (515875) 345 kV line CKT 1, near MATHWSN7. a. Apply fault at the MATHWSN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9011-3PH	P1	3 phase fault on NORTWST7 345 kV (514880) to MATHWSN7 345 kV (515497) line CKT 1,near NORTWST7. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9012-3PH	P1	3 phase fault on MINCO 7 345 kV (514801) to CIMARON7 345 kV (514901) line CKT 1, near MINCO 7. a. Apply fault at the MINCO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9013-3PH	P1	3 phase fault on MINCO 7 345 kV (514801) to MNCWND37 345 kV (515549) line CKT 1, near MINCO 7. a. Apply fault at the MINCO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generators G15-057-GEN (584953) (584954) (584955).** **Trip generators G14-056-GEN (515943) (584064) (584067).** **Trip generators MINCO-WTG31 (599117), MINCO-WTG32 (515551), MINCO-WTG33 (599119), MINCO-WTG34 (599120).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9014-3PH	P1	3 phase fault on MINCO 7 345 kV (514801) to MCNOWND7 345 kV (515444) line CKT 1, near MINCO 7. a. Apply fault at the MINCO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator MINCOWNG1 (515907)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9015-3PH	P1	3 phase fault on MINCO 7 345 kV (514801) to GRACMNT7 345 kV (515800) line CKT 1, near MINCO 7. a. Apply fault at the MINCO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9016-3PH	P1	3 phase fault on GRACMNT7 345 kV (515800) to GEN-2015-093 345 kV (585270) line CKT 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator G15-093-GEN1 (525273).** **Trip generator G15-093-GEN2 (525274).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9017-3PH	P1	3 phase fault on the GRACMNT7 345 kV (515800) to GRACMNT4 138 kV (515802) to GRACMNT11 13.8 kV (515801) XFMR CKT 1, near GRACMNT7 345 kV. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9018-3PH	P1	3 phase fault on GRACMNT7 345 kV (515800) to G16-037-TAP 345 kV (560078) line CKT 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9019-3PH	P1	3 phase fault on GRACMNT7 345 kV (515800) to G16-091-TAP 345 kV (587744) line CKT 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9020-3PH	P1	3 phase fault on G16-037-TAP 345 kV (560078) to GEN-2016-037 345 kV (587230) line CKT 1, near G16-037-TAP. a. Apply fault at the G16-037-TAP 345 kV bus. b. Clear fault after 5 cycles and trip 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 5 cycles, then trip the line in (b) and remove fault.
FLT9021-3PH	P1	3 phase fault on G16-037-TAP 345 kV (560078) to CHISHOLM7 345 kV (511553) line CKT 1, near G16-037-TAP. a. Apply fault at the G16-037-TAP 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9022-3PH	P1	3 phase fault on G16-091-TAP 345 kV (587744) to GEN-2016-095 345 kV (587770) line CKT 1, near G16-091-TAP a. Apply fault at the G16-091-TAP 345 kV bus. b. Clear fault after 5 cycles and trip 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 5 cycles, then trip the line in (b) and remove fault.
FLT9023-3PH	P1	3 phase fault on G16-091-TAP 345 kV (587744) to GEN-2016-091 345 kV (587740) line CKT 1, near G16-091-TAP. a. Apply fault at the G16-091-TAP 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator G16-001-GEN1 (587743).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9024-3PH	P1	3 phase fault on G16-091-TAP 345 kV (587744) to L.E.S-7 345 kV (511468) line CKT 1, near G16-091-TAP. a. Apply fault at the G16-091-TAP 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9025-3PH	P1	3 phase fault on GRACMNT4 138 kV (515802) to ANADARK4 138 kV (520814) line CKT 1, near GRACMNT4. a. Apply fault at the GRACMNT4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9026-3PH	P1	3 phase fault on GRACMNT4 138 kV (515802) to WASHITA4 138 kV (521089) line CKT 1, near GRACMNT4. a. Apply fault at the GRACMNT4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9027-3PH	P1	3 phase fault on CIMARON4 138 kV (514898) to SARA 4 138 kV (514895) line CKT 1, near CIMARON4. a. Apply fault at the CIMARON4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9028-3PH	P1	3 phase fault on CIMARON4 138 kV (514898) to HAYMAKR4 138 kV (514863) line CKT 1, near CIMARON4. a. Apply fault at the CIMARON4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.D44
FLT9029-3PH	P1	3 phase fault on CIMARON4 138 kV (514898) to CAECHAL4 138 kV (514894) line CKT 1, near CIMARON4. a. Apply fault at the CIMARON4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.D44
FLT9030-3PH	P1	3 phase fault on CIMARON4 138 kV (514898) to TUTCONT4 138 kV (511425) line CKT 1, near CIMARON4. a. Apply fault at the CIMARON4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.D44
FLT9031-3PH	P1	3 phase fault on CIMARON4 138 kV (514898) to JENSENT4 138 kV (514820) line CKT 1, near CIMARON4. a. Apply fault at the CIMARON4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.D44
FLT9032-3PH	P1	3 phase fault on CIMARON4 138 kV (514898) to EL-RENO4 138 kV (514819) line CKT 1, near CIMARON4. a. Apply fault at the CIMARON4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.D44
FLT9016-PO2	P6	**Prior Outage of MINCO 7 345 kV (514801) to CIMARON7 345 kV (514901) line CKT 1;** 3 phase fault on GRACMNT7 345 kV (515800) to GEN-2015-093 345 kV (585270) line CKT 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator G15-093-GEN1 (525273)** **Trip generator G15-093-GEN2 (525274)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9017-PO2	P6	**Prior Outage of MINCO 7 345 kV (514801) to CIMARON7 345 kV (514901) line CKT 1;** 3 phase fault on the GRACMNT7 345 kV (515800) to GRACMNT4 138 kV (515802) to GRACMNT11 13.8 kV (515801) XFMR CKT 1, near GRACMNT7 345 kV. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9018-PO2	P6	**Prior Outage of MINCO 7 345 kV (514801) to CIMARON7 345 kV (514901) line CKT 1;** 3 phase fault on GRACMNT7 345 kV (515800) to G16-037-TAP 345 kV (560078) line CKT 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9019-PO2	P6	**Prior Outage of MINCO 7 345 kV (514801) to CIMARON7 345 kV (514901) line CKT 1;** 3 phase fault on GRACMNT7 345 kV (515800) to G16-091-TAP 345 kV (587744) line CKT 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT01-PO4	P6	**Prior Outage of MINCO 7 345 kV (514801) to GRACMNT7 345 kV (515800) line CKT 1;** 3 phase fault on CIMARON7 345 kV (514901) to MATHWSN7 345 kV (515497) line CKT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT02-PO4	P6	**Prior Outage of MINCO 7 345 kV (514801) to GRACMNT7 345 kV (515800) line CKT 1;** 3 phase fault on CIMARON7 345 kV (514901) to NORTWST7 345 kV (514880) line CKT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT04-PO4	P6	**Prior Outage of MINCO 7 345 kV (514801) to GRACMNT7 345 kV (515800) line CKT 1;** 3 phase fault on CIMARON7 345 kV (514901) to DRAPER 7 345 kV (514934) line CKT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT05-PO4	P6	**Prior Outage of MINCO 7 345 kV (514801) to GRACMNT7 345 kV (515800) line CKT 1;** 3 phase fault on the CIMARON7 345 kV (514901) to CIMARON4 138 kV (514898) to CIMARO11 13.8 kV (515714) XFMR CKT 1, near CIMARON7 345 kV. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9001-PO4	P6	**Prior Outage of MINCO 7 345 kV (514801) to GRACMNT7 345 kV (515800) line CKT 1;** 3 phase fault on CIMARON7 345 kV (514901) to FSHRTAP7 345 kV (515610) line CKT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generators CANDIAN_WTG1 (599114), CANDIAN_WTG2 (599116).** **Trip generators KNGFSHR-GEN1 (599122), KNGFSHR-GEN2 (599124).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT1001-SB	P4	**Stuck Breaker on at GRACMNT4 (515802) at 138kV** a. Apply single-phase fault at GRACMNT4 (515802) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the GRACMNT4 (515802) to WASHITA4 (521089) 138kV line CKT 1. d. Trip the GRACMNT3 138/345/13.8kV (515802 /515800 /515801) transformer CKT 1.
FLT1002-SB	P4	**Stuck Breaker on at GRACMNT4 (515802) at 138kV** a. Apply single-phase fault at GRACMNT4 (515802) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the GRACMNT3 (515802) to ANADARK4 (520814) 138kV line CKT 1. d. Trip the GRACMNT3 138/345/13.8kV (515802 /515800 /515801) transformer CKT 1.
FLT1003-SB	P4	**Stuck Breaker on at GRACMNT4 (515802) at 138kV** a. Apply single-phase fault at GRACMNT4 (515802) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the GRACMNT3 (515802) to ANADARK4 (520814) 138kV line CKT 1. d. Trip the GRACMNT4 (515802) to WASHITA4 (521089) 138kV line CKT 2.
FLT1004-SB	P4	**Stuck Breaker on at GRACMNT4 (515802) at 138kV** a. Apply single-phase fault at GRACMNT4 (515802) on the 138kV bus. b .Clear fault after 16 cycles and remove fault. c. Trip the GRACMNT4 (515802) to WASHITA4 (521089) 138kV line CKT 1. d. Trip the GRACMNT4 (515802) to WASHITA4 (521089) 138kV line CKT 2.
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 (514801) 345kV line CKT 1. d. Trip the GRACMNT7 (515800) to G16-091-TAP (587744) 345kV line CKT 1.
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.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
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 (514801) 345kV line CKT 1. d. Trip the GRACMNT7 (515800) to G16-037-TAP (560078) 345kV line CKT 1.
FLT1009-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.
FLT1010-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) - FSHRTAP7 (515610) 345kV line CKT 1. **Trip generators connected to this POI bus KNGFSHR-GEN1 (599122), KNGFSHR-GEN2 (599124), CANDIAN_WTG1 (599114), CANDIAN_WTG2 (599116).** d. CIMARON7 (514901) - MINCO (514801) 345kV line CKT 1.
FLT1011-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) - DRAPER (514934) 345kV line CKT 1 d. CIMARON7 345 kV (514901) / CIMARON4 138 kV (514898) / CIMARON21 13.8 kV (515715) transformer CKT 1.

6.3 Results

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

Table 6-2: GEN-2011-010 & GEN-2014-005 Dynamic Stability Results

Fault ID	17WP			18SP			26SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT01-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT65-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT67-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT68-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT69-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT70-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT75-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable**	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable**	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable**	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable**	Pass	Pass	Stable**	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable*	Pass	Pass	Stable*
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable*	Pass	Pass	Stable*
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9029-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9030-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9031-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9032-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT20-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	17WP			18SP			26SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT75-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT01-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT75-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT01-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

***RELAY SLNOS1 # 1 tripped 523777 [WHEELER 6230.00] TO 523779 [STLN-DEMARC6230.00] CKT 1 during the fault**
****RELAY SLNOS1 # 1 tripped 523779 [STLN-DEMARC6230.00] TO 511541 [SWEETWT6 230.00] CKT 1 during the fault**

During faults FLT9016, FLT9017, FLT9018, and FLT9019 (loss of a line or transformer connected to Gracemont 345 kV), the SLNOS1 #1 relay tripped the STLN-DEMARC6 to

Sweetwater 230 kV Circuit 1 line during the fault in the 17WP and 18SP cases. This was observed in both the pre and post modification cases, so it was not attributed to this modification request.

During faults FLT9020 and FLT9021 (loss of a line connected to G16-037-TAP 345 kV), the SLNOS1 #1 relay tripped the Wheeler to STLN-DEMARC6 230 kV Circuit 1 line during the fault in the 18SP and 26SP cases. This was observed in both the pre and post modification cases, so it was not attributed to this modification request.

There were no damping or voltage recovery violations 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-2011-010 and GEN-2014-005 (115.18 MW) exceeds the GIA Interconnection Service amount, 106.5 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-2011-010 and GEN-2014-005 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-2011-010 and GEN-2014-005 requested a Modification Request Impact Study to assess the impact of the turbine and facility change to a configuration of 17 x GE 1.69 MW + 42 x GE 1.85 MW + 1 x GE 1.85 MW + 3 x GE 2.3 MW for a total generating capacity of 115.18 MW. The generating capacity for GEN-2011-010 and GEN-2014-005 (115.18 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, 106.5 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 includes the use of a Power Plant Controller (PPC) to limit the power injected into the POI.

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

SPP determined that power flow should not be performed based on the POI MW injection increase of 2.89% compared to the recently studied DISIS-2017-001 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, GE, short circuit and dynamic stability analyses were required because of the project capacity increase and the use of a PPC.

The scope of this modification request study included charging current compensation analysis, short circuit analysis, and dynamic stability analysis. Aneden updated the GIRs that had POIs within 3 buses of the GEN-2011-010 and GEN-2014-005 POI as applicable based on SPP's confirmation of the latest project configurations. Modeling updates for GEN-2007-043, GEN-2014-056, GEN-2015-057, GEN-2015-063, GEN-2016-037, GEN-2016-045, GEN-2016-057, and GEN-2016-131 were included in the base models.

The results of the charging current compensation analysis performed using the 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak models showed that the GEN-2011-010 and GEN-2014-005 project needed 14.74 MVAr of reactor shunts on the 34.5 kV bus of the project substation, a decrease from the 15.8 MVAr found for the existing GEN-2011-010 and GEN-2014-005 configuration. 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-2011-010 and GEN-2014-005 contribution to three-phase fault currents in the immediate systems at or near GEN-2011-010 and GEN-2014-005 was not greater than 0.57 kA for the 2018SP and 2026SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2011-010 and GEN-2014-005 generators online were below 45 kA for the 2018SP and 2026SP models.

The dynamic stability analysis was performed using the three modified study models, 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak. Up to 65 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

The results of the dynamic stability analysis showed that there were no damping or voltage recovery violations 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.