GEN-2016-045 & GEN-2016-057

Impact Restudy for Generator Modification

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REVISION HISTORY

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01/31/2020	SPP	Initial report issued.

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SUMMARY

The GEN-2016-045 & GEN-2016-057 Interconnection Customer has requested a modification to its Interconnection Request of a total combined capacity of 998.2 MW. This system impact restudy was performed to determine the effects of changing turbines from 434 GE 2.3 MW wind turbine generators (for a total of 998.2 MW) to 338 GE 2.82 MW and 18 GE 2.5 MW wind turbine generators (for a total of 998.18 MW). In addition, the modification request included changes to the collection system, generation interconnection line and the generator substation transformer. The point of interconnection (POI) for GEN-2016-045 & GEN-2016-057 remains at the Mathewson 345 kV Substation.

This study was performed by Aneden Consulting to determine whether the request for modification is considered Material. A short circuit analysis, a low-wind/no-wind condition analysis, powerflow analysis and stability analysis was performed for this modification request. The study report follows this executive summary.

The power flow analysis was performed due to the configuration change of the modification request, both GEN-2016-045 and GEN-2016-057 were studied as a single combined facility comprising of three collections of wind turbines. The power flow analysis showed that the high voltages and loading violations previously identified in the DISIS-2016-001-1 report were mitigated by the previously identified upgrades as well as the modified generating facility design and that the modification did not cause additional thermal or voltage constraints requiring mitigation by DISIS-2016-001 or DISIS-2016-002 interconnection requests.

The generating facility will be required to maintain a dynamic 95% lagging (providing VARs) and 95% leading (absorbing VArs) at the high-side of the generator substation in accordance with FERC Order 827. Additionally, the project will be required to install approximately 115 MVArs of reactor shunts on its substation 345 kV bus or provide an alternate means of reactive power compensation. 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/no-wind conditions.

There were no machine rotor angle damping or transient voltage recovery violations observed in the simulated fault events. Additionally, the project wind farm 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 is not considered Material.

It should be noted that this study analyzed the requested modification to change generator technology and layout. This study analyzed many of the most probable contingencies, but it is not an all-inclusive list and cannot account for every operational situation. It is likely that the customer may be required to reduce its generation output to 0 MW, 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.

A: CONSULTANT'S MATERIAL MODIFICATION STUDY REPORT

See next page for the Consultant's Material Modification Study report.

Submitted to

Southwest Power Pool

SPP Southwest Power Pool

Report On

GEN-2016-045 and GEN-2016-057 Modification Request Impact Study

Revision R0

Date of Submittal
January 29, 2020

anedenconsulting.com

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Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2016-045 and GEN-2016-057, two active generation interconnection requests with the same point of interconnection (POI) at the Mathewson 345kV Substation.

The GEN-2016-045 and GEN-2016-057 projects were proposed to interconnect in Oklahoma Gas & Electric (OKGE) control area with capacities of 499.1 MW each for a combined total capacity of 998.2 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2016-045 and GEN-2016-057, to change the combined turbine configuration to a total of 338 x GE 2.82MW + 18 x GE 2.5MW, for a total capacity of 998.18 MW. In addition, the modification request included changes to the generation interconnection line, collection system and the generator substation transformers. The existing and modified configurations for GEN-2016-045 and GEN-2016-057 are shown in Table ES-2 and Table ES-3 respectively.

Table ES-1: Existing GEN-2016-045 & GEN-2016-057 Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2016-045	499.1	217 x GE 2.3MW	Mathewson 345 kV Substation (515497)
GEN-2016-057	499.1	217 x GE 2.3MW	Mathewson 345 kV Substation (515497)

Table ES-2: GEN-2016-045 & GEN-2016-057 Existing Configuration

<table>
<tr><th>Facility</th><th colspan="4">Existing GEN-2016-045</th><th colspan="4">Existing GEN-2016-057</th></tr>
<tr><td>Point of Interconnection</td><td colspan="4">Mathewson 345 kV Substation (515497)</td><td colspan="4">Mathewson 345 kV Substation (515497)</td></tr>
<tr><td>Configuration/Capacity</td><td colspan="4">217 x GE 2.3MW = 499.1 MW</td><td colspan="4">217 x GE 2.3MW = 499.1 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td colspan="2">Length = 290.5 miles
R = 0.016350 pu
X = 0.144680 pu
B = 2.536120 pu</td><td colspan="2">Length = 302.5 miles
R = 0.017030 pu
X = 0.150660 pu
B = 2.640880 pu</td><td colspan="2">Length = 296.9 miles
R = 0.016710 pu
X = 0.147870 pu
B = 2.591370 pu</td><td colspan="2">Length = 318.6 miles
R = 0.017930 pu
X = 0.158680 pu
B = 2.781430 pu</td></tr>
<tr><td>Main Substation Transformer</td><td>Z = 9%, Winding 100 MVA, Rating 166 MVA</td><td>Z = 9%, Winding 100 MVA, Rating 166 MVA</td><td>Z = 9%, Winding 100 MVA, Rating 166 MVA</td><td>Z = 9%, Winding 100 MVA, Rating 166 MVA</td><td>Z = 9%, Winding 100 MVA, Rating 166 MVA</td><td>Z = 9%, Winding 100 MVA, Rating 166 MVA</td><td>Z = 9%, Winding 100 MVA, Rating 166 MVA</td><td>Z = 9%, Winding 100 MVA, Rating 166 MVA</td></tr>
<tr><td>GSU Transformer</td><td colspan="2">Gen 1 Equivalent Qty: 108:
Z = 5.7%, Rating 272.5 MVA</td><td colspan="2">Gen 2 Equivalent Qty: 109:
Z = 5.7%, Rating 270 MVA</td><td colspan="2">Gen 1 Equivalent Qty: 108:
Z = 5.7%, Rating 272.5 MVA</td><td colspan="2">Gen 2 Equivalent Qty: 109:
Z = 5.7%, Rating 270 MVA</td></tr>
<tr><td>Equivalent Collector Line</td><td colspan="2">R = 0.000230 pu
X = 0.000253 pu
B = 0.115560 pu</td><td colspan="2">R = 0.000263 pu
X = 0.000318 pu
B = 0.133410 pu</td><td colspan="2">R = 0.000245 pu
X = 0.000277 pu
B = 0.123970 pu</td><td colspan="2">R = 0.000237 pu
X = 0.000255 pu
B = 0.118500 pu</td></tr>
<tr><td>Reactive Power Devices</td><td colspan="2">3 x 50 MVAR 34.5 kV Reactor</td><td colspan="2">3 x 50 MVAR 34.5 kV Reactor</td><td colspan="2">3 x 50 MVAR 34.5 kV Reactor</td><td colspan="2">3 x 50 MVAR 34.5 kV Reactor</td></tr>
</table>

Table ES-3: GEN-2016-045 & GEN-2016-057 Modification Request

<table>
<tr><th rowspan="2">Facility</th><th colspan="12">Modification GEN-2016-045 & GEN-2016-057</th></tr>
<tr><th colspan="4">Collection 1</th><th colspan="4">Collection 2</th><th colspan="4">Collection 3</th></tr>
<tr><td>Point of Interconnection</td><td colspan="12">Mathewson 345 kV Substation (515497)</td></tr>
<tr><td>Configuration/ Capacity</td><td colspan="12">338 x GE 2.82MW + 18 x GE 2.5MW = 998.16 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td colspan="4">Length = 51.5 miles
R = 0.001334 pu
X = 0.024250 pu
B = 0.464678 pu</td><td colspan="4">Length = 21.6 miles
R = 0.000904 pu
X = 0.010462 pu
B = 0.189396 pu</td><td colspan="4">Length = 7.78 miles
R = 0.000326 pu
X = 0.003768 pu
B = 0.068218 pu</td></tr>
<tr><td>Main Substation Transformer</td><td colspan="2">Z12 = 9%, Z23 = 4.5%, Z13 = 18%, Winding 120 MVA, Rating 200 MVA</td><td colspan="2">Z12 = 9%, Z23 = 4.5%, Z13 = 18%, Winding 120 MVA, Rating 200 MVA</td><td colspan="2">Z12 = 9%, Z23 = 4.5%, Z13 = 18%, Winding 120 MVA, Rating 200 MVA</td><td colspan="2">Z12 = 9%, Z23 = 4.5%, Z13 = 18%, Winding 120 MVA, Rating 200 MVA</td><td colspan="2">Z12 = 9%, Z23 = 4.5%, Z13 = 18%, Winding 120 MVA, Rating 200 MVA</td><td colspan="2">Z12 = 9%, Z23 = 4.5%, Z13 = 18%, Winding 120 MVA, Rating 200 MVA</td></tr>
<tr><td>GSU Transformer</td><td colspan="2">Gen 1 Equivalent Qty: 54:
Z = 7.01%, Rating 168.7 MVA</td><td colspan="2">Gen 2 Equivalent Qty: 58:
Z = 7.03%, Rating 180.6 MVA</td><td colspan="2">Gen 1 Equivalent Qty: 63:
Z = 7.02%, Rating 196.4 MVA</td><td colspan="2">Gen 2 Equivalent Qty: 59:
Z = 6.98%, Rating 185.5 MVA</td><td colspan="2">Gen 1 Equivalent Qty: 59:
Z = 6.98%, Rating 185.5 MVA</td><td colspan="2">Gen 2 Equivalent Qty: 63:
Z = 6.97%, Rating 198.4 MVA</td></tr>
<tr><td>Equivalent Collector Line</td><td colspan="2">R = 0.005955 pu
X = 0.006825 pu
B = 0.056912 pu</td><td colspan="2">R = 0.005460pu
X = 0.005780 pu
B = 0.062699 pu</td><td colspan="2">R = 0.005487 pu
X = 0.006091 pu
B = 0.069280 pu</td><td colspan="2">R = 0.006251 pu
X = 0.006987 pu
B = 0.068995 pu</td><td colspan="2">R = 0.007703 pu
X = 0.009181 pu
B = 0.084861 pu</td><td colspan="2">R = 0.006239 pu
X = 0.007707 pu
B = 0.078683 pu</td></tr>
<tr><td>Reactive Power Devices</td><td colspan="3">1 x 60 MVAR 34.5 kV Reactor</td><td colspan="3">1 x 45 MVAR 34.5 kV Reactor</td><td colspan="3">N/A</td><td colspan="3">N/A</td></tr>
</table>

GEN-2016-045 and GEN-2016-057 were both originally studied as part of Group 1 in the DISIS-2016-001. Due to the configuration of the modification request, both GEN-2016-045 and GEN-2016-057 were studied as a single combined facility comprising of three collections of wind turbines. Aneden performed power flow analysis, reactive power analysis, short circuit analysis, and dynamic stability analysis.

The power flow analysis was performed using the DISIS-2016-001 Group 00 and Group 1 ERIS power flow models, and DISIS-2016-002 Group 1 ERIS power flow models. The reactive power, short circuit, and dynamic stability analyses were completed using the modification request data using the DISIS-2016-002 Restudy #1 Group 1 study models:

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

All analyses were performed using the PTI PSS/E version 33.7 software and the results are summarized below.

The power flow analysis showed that the modified study models did not show the high voltages and loading violations previously identified in the DISIS-2016-001-1 report (ReStudy#1) as shown in Table ES-4 and Table ES-5. ReStudy#1 models were based on the 2015-series Integrated Transmission Planning (ITP) models while this Study (TC and MRIS results) used the most recent

DISIS models based on the 2016-series Integrated Transmission Planning models[1]. Note that the models used in this study included the following upgrades previously identified in ReStudy#1:

1. Cimarron – Draper Lake 345 kV Line Upgrade (SPP-NTC-200416)
2. DeGrasse 345/138kV Project (SPP-NTC-200418 & 200419)

Table ES-4: GEN-2016-045 & GEN-2016-057 MRIS Impact on Existing Voltage Violations (DISIS-2016-001-1)

Monitored Element	*Restudy #1 TC Voltage (PU)	TC Voltage (PU)	Contingency	Currently Assigned Upgrades	MRIS Modification (PU)
GEN-2016-045 345.00 345 kV	1.322582	1.31128	System Intact	GEN-2016-045 & GEN-2015-057 assigned reactors	No Violation, Mitigation Not Required
GEN-2016-045 345.00 345 kV	1.347816	1.33955	MATHWSN7 345.00 - NORTHWEST 345KV CKT 1		No Violation, Mitigation Not Required
MATHWSN7 345.00 345 KV	1.060389	1.06667	TATONGA7 345.00 - WOODWARD DISTRICT EHV 345KV CKT 1		No Violation, Mitigation Not Required

*Restudy #1 TC Voltage data is from the DISIS-2016-001 Group 1 Report

Table ES-5: GEN-2016-045 & GEN-2016-057 MRIS Impact on Existing Loading Violations (DISIS-2016-001-1)

Monitored Element	Limiting Rate A/B (MVA)	*Restudy #1 TC %Loading (%MVA)	TC %Loading (%Loading)	Contingency	Currently Assigned Upgrades	MRIS Modification (%Loading)
CIMARRON - DRAPER LAKE 345KV CKT 1	717 (1195)**	104.8577	<100	System Intact	Previously Assigned per SPPNTC-200416**	Mitigation Not Required (<100%)
DGRASSE4 138.00 - ROSE_VALLEY 138.00 138KV CKT 1	143	165.2136	<100	System Intact	DeGrasse 345/138kV Project (SPP-NTC-200418 & 200419)***	Mitigation Not Required (<100%)
DGRASSE4 138.00 - ROSE_VALLEY 138.00 138KV CKT 1	187	139.4533	<100	WOODWARD EHV - WWPAR4 138.00 138KV CKT 1		Mitigation Not Required (<100%)
FPL SWITCH – WOODWARD 138KV CKT 1	153	112.0593	<100	DGRASSE4 138.00 - ROSE_VALLEY 138.00 138KV CKT 1		Mitigation Not Required (<100%)
NOEL_SW 138.00 - ROSE_VALLEY 138.00 138KV CKT 1	200	111.1773	<100	System Intact		Mitigation Not Required (<100%)
NOEL_SW 138.00 - ROSE_VALLEY 138.00 138KV CKT 1	234	105.2112	<100	WOODWARD EHV - WWPAR4 138.00 138KV CKT 1		Mitigation Not Required (<100%)

*Restudy #1 TC %Loading data is from the DISIS-2016-001 Group 1 Report
**Cimarron - Draper Lake 345 kV line is upgraded to 1195 MVA in the models used for this Study
*** The DeGrasse 345/138 kV Project is in service in the 21L0, 21SP, 21WP, 26SP models used for this Study

The modified study models did cause a slight increase on the loading violation previously identified in the DISIS-2016-002 report as shown in Table ES-6. The Dover – Henessey 138 kV line overload was attributed to the GEN-2016-118 project in the DISIS-2016-002 report and it is confirmed that the currently assigned mitigation for the Dover – Henessey 138 kV line overload will be sufficient.

[1] 2015-series Integrated Transmission Planning (ITP) models were used for the 2016 ITP-Near Term analysis
2016-series Integrated Transmission Planning models were used for the 2017 ITP-Near Term analysis

Table ES-6: GEN-2016-045 & GEN-2016-057 MRIS Impact on Existing Loading Violations (DISIS-2016-002)

Monitored Element	Limiting Rate A/B (MVA)	*DISIS-2016-002 TC %Loading (%MVA)	TC %Loading (%Loading)	Contingency	Currently Assigned Upgrades	MRIS Modification (%Loading)
DOVER SW - HENESSEY 138 kV CKT 1	191	105.28	104.92	CRESENT - TWIN LAKES 138 kV CKT 1	Terminal Equipment Upgrade	105.33

*TC %Loading data is from the DISIS-2016-002 Group 1 Report

The modification did not cause additional thermal or voltage constraints with a relevant TDF (>3% for N-0, or >20% for N-1).

A power factor analysis was not performed as there was no change in the point of interconnection for GEN-2016-045 and GEN-2016-057.

The results of the reactive power analysis, also known as the low-wind/no-wind condition analysis, derived from all three models showed that the combined GEN-2016-045 and GEN-2016-057 facility require a 115 MVAr shunt reactor on the 345 kV bus of the project substation. The shunt reactor is needed to reduce the reactive power transfer at the POI to approximately zero during low/no wind conditions while the generation interconnection projects remain connected to the grid.

The results from short circuit analysis showed that the maximum change in the fault currents in the immediate systems at or near GEN-2016-045 and GEN-2016-057 POI was 2.14 kA. All three-phase current levels with the GEN-2016-045 and GEN-2016-057 generators online were below 50 kA and 52 kA in the 2018SP and 2026SP models respectively. The GEN-2016-045 and GEN-2016-057 POI bus had a maximum fault current of 32.68 kA.

The dynamic stability analysis was performed using the three loading scenarios 2017WP, 2018SP and 2026SP simulating up to 130 contingencies that included three-phase faults, three phase faults on prior outage cases, and single-line-to-ground faults stuck breakers faults.

There were no machine rotor angle damping or transient voltage recovery violations observed in the simulated fault events. Additionally, the project wind farm generators were 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 results of this Study show that the GEN-2016-045 and GEN-2016-057 Modification Request does not constitute a material modification.

1.0 Introduction

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2016-045 and GEN-2016-057, two active generation interconnection requests with the same point of interconnection (POI) at the Mathewson 345kV Substation.

The GEN-2016-045 and GEN-2016-057 projects were proposed to interconnect in the Oklahoma Gas & Electric (OKGE) control area with capacities of 499.1 MW each as shown in Table 1-1 below. Details of the modification request as provided in Section 2.0 below.

Table 1-1: Existing GEN-2016-045 & GEN-2016-057 Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2016-045	499.1	217 x GE 2.3MW	Mathewson 345 kV Substation (515497)
GEN-2016-057	499.1	217 x GE 2.3MW	Mathewson 345 kV Substation (515497)

1.1 Scope

The Study included power flow, reactive power, short circuit, and dynamic stability analyses. The methodology, assumptions and results of the analyses are presented in the following six main sections:

1. Project and Modification Request
2. Power Flow Analysis
3. Reactive Power Analysis
4. Short Circuit Analysis
5. Dynamic Stability Analysis
6. Conclusions

Aneden performed a power flow analysis using the DISIS-2016-001 Group 00 and Group 1 (ERIS) and DISIS-2016-002 Group 1 (ERIS) power flow models which were modified to include the modification request data.

The reactive power, short circuit and dynamic stability analyses were completed using a set of modified study models developed using the modification request data and the three DISIS-2016-002 Restudy #1 study models:

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

All analyses were performed using the PTI PSS/E version 33.7 software. The results of each analysis are presented in the following sections.

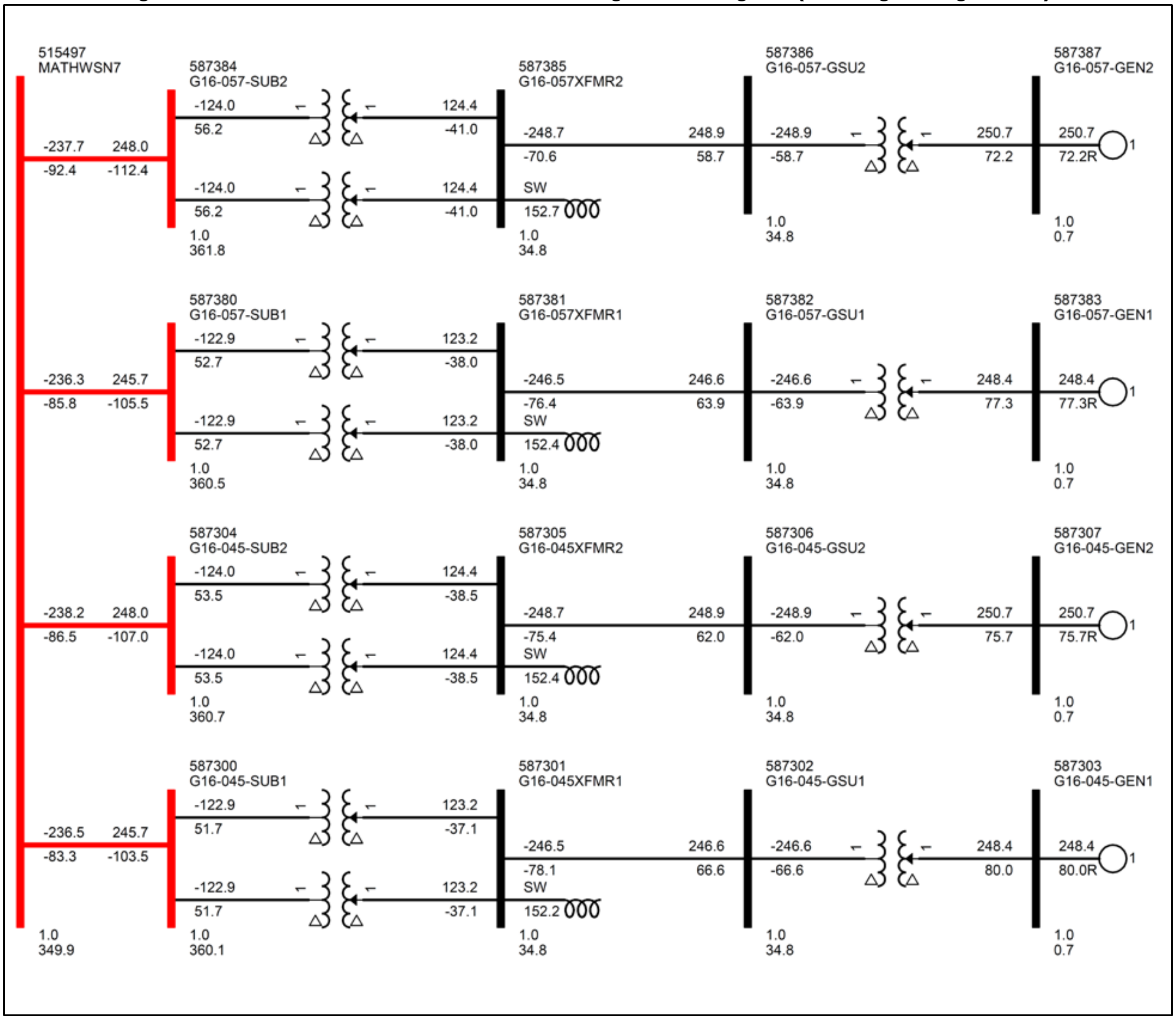
1.2 Study Limitations

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

Figure 2-1 shows the power flow model single line diagram for the existing GEN-2016-045 and GEN-2016-057 configurations. GEN-2016-045 and GEN-2016-057 were both originally studied as part of Group 1 in DISIS-2016-001.

Figure 2-1: GEN-2016-045 & GEN-2016-057 Single Line Diagram (Existing Configuration)



This Study has been requested to evaluate the modification of GEN-2016-045 and GEN-2016-057, to a combined turbine configuration of 338 x GE 2.82MW + 18 x GE 2.5MW, for a total capacity of 998.18 MW. In addition, the modification request also included changes to the collection system, the generator substation transformers and the generation interconnection line. The major modification request changes are shown in Figure 2-2, Table 2-1, and Table 2-2 below.

Figure 2-2: GEN-2016-045 & GEN-2016-057 Single Line Diagram (New Configuration)

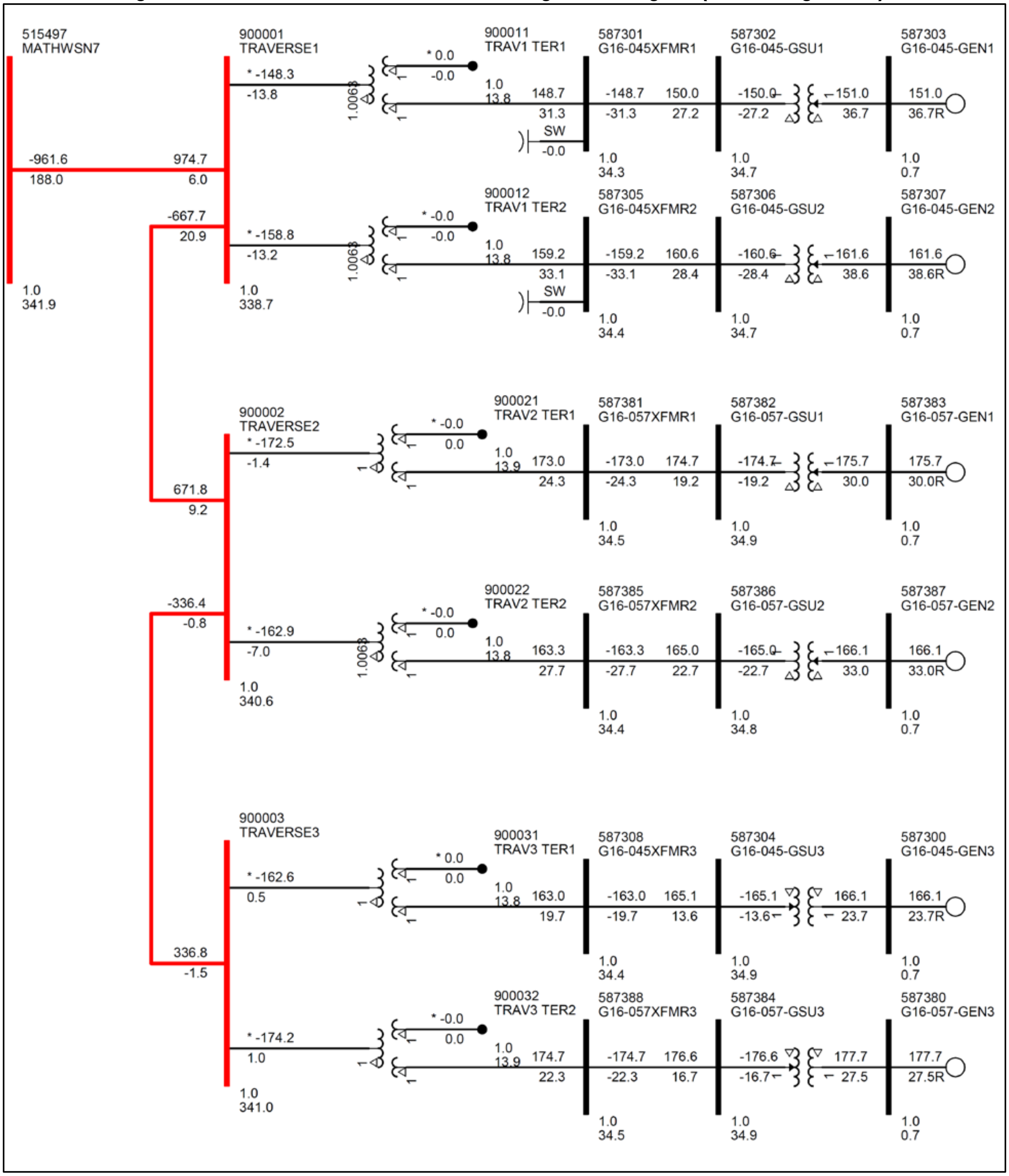


Table 2-1: Existing GEN-2016-045 & GEN-2016-057 Configuration

<table>
<tr><th>Facility</th><th colspan="4">Existing GEN-2016-045</th><th colspan="4">Existing GEN-2016-057</th></tr>
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</table>

Table 2-2: GEN-2016-045 & GEN-2016-057 Modification Request

<table>
<tr><th rowspan="2">Facility</th><th colspan="6">Modification GEN-2016-045 & GEN-2016-057</th></tr>
<tr><th colspan="2">Collection 1</th><th colspan="2">Collection 2</th><th colspan="2">Collection 3</th></tr>
<tr><td>Point of Interconnection</td><td colspan="6">Mathewson 345 kV Substation (515497)</td></tr>
<tr><td>Configuration/ Capacity</td><td colspan="6">338 x GE 2.82MW + 18 x GE 2.5MW = 998.16 MW</td></tr>
<tr><td>Generation Interconnection Line(s)</td><td colspan="2">Length = 51.5 miles
R = 0.001334 pu
X = 0.024250 pu
B = 0.464678 pu</td><td colspan="2">Length = 21.6 miles
R = 0.000904 pu
X = 0.010462 pu
B = 0.189396 pu</td><td colspan="2">Length = 7.78 miles
R = 0.000326 pu
X = 0.003768 pu
B = 0.068218 pu</td></tr>
<tr><td>Main Substation Transformer(s)</td><td>Z12 = 9%, Z23 = 4.5%, Z13 = 18%, Winding 120 MVA, Rating 200 MVA</td><td>Z12 = 9%, Z23 = 4.5%, Z13 = 18%, Winding 120 MVA, Rating 200 MVA</td><td>Z12 = 9%, Z23 = 4.5%, Z13 = 18%, Winding 120 MVA, Rating 200 MVA</td><td>Z12 = 9%, Z23 = 4.5%, Z13 = 18%, Winding 120 MVA, Rating 200 MVA</td><td>Z12 = 9%, Z23 = 4.5%, Z13 = 18%, Winding 120 MVA, Rating 200 MVA</td><td>Z12 = 9%, Z23 = 4.5%, Z13 = 18%, Winding 120 MVA, Rating 200 MVA</td></tr>
<tr><td>GSU Transformer</td><td>Gen 1 Equivalent Qty: 54:
Z = 7.01%, Rating 168.7 MVA</td><td>Gen 2 Equivalent Qty: 58:
Z = 7.03%, Rating 180.6 MVA</td><td>Gen 1 Equivalent Qty: 63:
Z = 7.02%, Rating 196.4 MVA</td><td>Gen 2 Equivalent Qty: 59:
Z = 6.98%, Rating 185.5 MVA</td><td>Gen 1 Equivalent Qty: 59:
Z = 6.98%, Rating 185.5 MVA</td><td>Gen 2 Equivalent Qty: 63:
Z = 6.97%, Rating 198.4 MVA</td></tr>
<tr><td>Equivalent Collector Line</td><td>R = 0.005955 pu
X = 0.006825 pu
B = 0.056912 pu</td><td>R = 0.005460pu
X = 0.005780 pu
B = 0.062699 pu</td><td>R = 0.005487 pu
X = 0.006091 pu
B = 0.069280 pu</td><td>R = 0.006251 pu
X = 0.006987 pu
B = 0.068995 pu</td><td>R = 0.007703 pu
X = 0.009181 pu
B = 0.084861 pu</td><td>R = 0.006239 pu
X = 0.007707 pu
B = 0.078683 pu</td></tr>
<tr><td>Reactive Power Devices</td><td>1 x 60 MVAR 34.5 kV Reactor</td><td>1 x 45 MVAR 34.5 kV Reactor</td><td colspan="2">N/A</td><td colspan="2">N/A</td></tr>
</table>

3.0 Power Flow Analysis

The power flow analysis was performed using the DISIS-2016-001 Group 00 and Group 1 ERIS power flow models, and DISIS-2016-002 Group 1 ERIS power flow models. The model development, power flow analysis methodology, and power flow results are presented in this Section. Detailed power flow results are provided in Appendix A.

3.1 Model Development

The Study cases were built using SPP provided ERIS models (baseline models). These baseline models were modified to represent the modification request details for GEN-2016-045 and GEN-2016-057.

The previous DISIS-2016-001-1 report used power flow models based on the 2015-series Integrated Transmission Planning (ITP) models used for the 2016 ITP-Near Term analysis. These models will be referenced as Restudy#1 models.

This Study used power flow models (Table 3-1) based on the 2016-series Integrated Transmission Planning models used for the 2017 ITP-Near Term analysis, which included the following Group 1 upgrades identified in the DISIS-2016-001-1 Report:

1. Cimarron – Draper Lake 345 kV Line Upgrade (SPP-NTC-200416)
    - 17WP, 18SP, 21SP, 21WP, 26SP
2. DeGrasse 345/138kV Project (SPP-NTC-200418 & 200419)
    - 21L, 21SP, 21WP, 26SP

Table 3-1: Power Flow DISIS Cases Evaluated

Case Year (Both BC & TC)*	DISIS-2016-001 Group 00	DISIS-2016-001 Group 01	DISIS-2016-002 Group 01
17WP	x	x	x
18SP	x	x	x
18G		x	x
21L		x	x
21SP	x	x	x
21WP	x	x	x
26SP	x	x	x

*BC Cases – Group 1 Models Dispatched to 0 MW,
TC Cases – Group 1 Models Dispatched to 20% or 100% Max Capacity for Group 00 and Group 1 respectively

3.2 Power Flow Analysis Methodology

A power flow analysis was conducted using DISIS-2016-001 Group 00 and Group 1, and DISIS-2016-002 Group 1 power flow models under Base Case (BC) conditions (Group 1 Models Dispatched to 0 MW) and Transfer Case (TC) conditions (Group 1 Models Dispatched to 20% or 100% Max Capacity for Group 00 and Group 1 respectively) as well as modified versions of these models with Modification Request Impact Study (MRIS) modifications (GEN-2016-045 and GEN-2016-057 online with new configuration). GEN-2016-045 and GEN-2016-

057 were dispatched to 100% in the Group 1 TC & MRIS cases and to 20% in the Group 00 cases.

The AC Contingency Calculation (ACCC) function of PSS/E was used to simulate system intact and contingencies provided by SPP. The system facilities were monitored for thermal and voltage impacts on all 69kV lines and above.

Network constraints were found using the PSS/E ACCC analysis along with TARA Transfer Distribution Factor (TDF) analysis for the entire cluster grouping.

For ERIS, thermal overloads are defined as being greater than 100% of Rate A for N-0 conditions, and greater than 100% of Rate B for N-1 contingencies. These overloads were then analyzed to determine if they meet any of the following three criteria:

- 3% Distribution Factor (DF) for N-0 conditions,
- 20% DF upon outage-based (N-1) conditions,
- or 3% DF on contingent elements that resulted in a non-converged solution.

ACCC analysis was also used to determine voltage constraints in accordance with the guidelines in the Transmission Owner planning criteria. The identified voltage constraints were analyzed to determine if they met all the following criteria:

- 3% DF on the identified element,
- and 2% change in pu voltage.

3.3 Results

Table 3-2 and Table 3-3 below show the results from the power flow analysis using the DISIS-2016-001 models. The results show that the high voltages and loading violations previously identified in the DISIS-2016-001-1 (ReStudy#1) report were no longer observed in the modification request results. The voltage violations were resolved due to the changes in the project generation interconnection line changes in the modification request and the loading violations were not observed because the upgrades were already included in the 2016-series cases.

Table 3-2: GEN-2016-045 & GEN-2016-057 MRIS Impact on Existing Voltage Violations (DISIS-2016-001-1)

Monitored Element	*Restudy #1 TC Voltage (PU)	TC Voltage (PU)	Contingency	Currently Assigned Upgrades	MRIS Modification (PU)
GEN-2016-045 345.00 345 kV	1.322582	1.31128	System Intact	GEN-2016-045 & GEN-2015-057 assigned reactors	No Violation, Mitigation Not Required
GEN-2016-045 345.00 345 kV	1.347816	1.33955	MATHWSN7 345.00 - NORTHWEST 345KV CKT 1		No Violation, Mitigation Not Required
MATHWSN7 345.00 345 KV	1.060389	1.06667	TATONGA7 345.00 - WOODWARD DISTRICT EHV 345KV CKT 1		No Violation, Mitigation Not Required

*Restudy #1 TC Voltage data is from the DISIS-2016-001 Group 1 Report

Table 3-3: GEN-2016-045 & GEN-2016-057 MRIS Impact on Existing Loading Violations (DISIS-2016-001-1)

Monitored Element	Limiting Rate A/B (MVA)	*Restudy #1 TC %Loading (%MVA)	TC %Loading (%Loading)	Contingency	Currently Assigned Upgrades	MRIS Modification (%Loading)
CIMARRON - DRAPER LAKE 345KV CKT 1	717 (1195)**	104.8577	<100	System Intact	Previously Assigned per SPPNTC-200416**	Mitigation Not Required (<100%)
DGRASSE4 138.00 - ROSE_VALLEY 138.00 138KV CKT 1	143	165.2136	<100	System Intact	DeGrasse 345/138kV Project (SPP-NTC-200418 & 200419)***	Mitigation Not Required (<100%)
DGRASSE4 138.00 - ROSE_VALLEY 138.00 138KV CKT 1	187	139.4533	<100	WOODWARD EHV - WWPAR4 138.00 138KV CKT 1		Mitigation Not Required (<100%)
FPL SWITCH – WOODWARD 138KV CKT 1	153	112.0593	<100	DGRASSE4 138.00 - ROSE_VALLEY 138.00 138KV CKT 1		Mitigation Not Required (<100%)
NOEL_SW 138.00 - ROSE_VALLEY 138.00 138KV CKT 1	200	111.1773	<100	System Intact		Mitigation Not Required (<100%)
NOEL_SW 138.00 - ROSE_VALLEY 138.00 138KV CKT 1	234	105.2112	<100	WOODWARD EHV - WWPAR4 138.00 138KV CKT 1		Mitigation Not Required (<100%)

*Restudy #1 TC %Loading data is from the DISIS-2016-001 Group 1 Report
**Cimarron - Draper Lake 345 kV line was upgraded to 1195 MVA in the models used for this Study
*** The DeGrasse 345/138 kV Project was in service in the 21L, 21SP, 21WP, 26SP models used for this Study

The GEN-2016-045 and GEN-2016-057 modification request changes did cause a slight increase on the loading violation previously identified in the DISIS-2016-002 report as shown in Table 3-4. The GEN-2016-045 and GEN-2016-057 TDF associated with the Diver – Henessey 138 kV line is below the 20% threshold. The Dover – Henessey 138 kV line overload was attributed to the GEN-2016-118 project in the DISIS-2016-002 report and it is confirmed that the currently assigned mitigation for the Dover – Henessey 138 kV line overload will be sufficient.

Table 3-4: GEN-2016-045 & GEN-2016-057 MRIS Impact on Existing Loading Violations (DISIS-2016-002)

Monitored Element	Limiting Rate A/B (MVA)	*DISIS-2016-002 TC %Loading (%MVA)	TC %Loading (%Loading)	Contingency	Currently Assigned Upgrades	MRIS Modification (%Loading)
DOVER SW - HENESSEY 138 kV CKT 1	191	105.28	104.92	CRESENT - TWIN LAKES 138 kV CKT 1	Terminal Equipment Upgrade	105.33

*TC %Loading data is from the DISIS-2016-002 Group 1 Report

Additional thermal overloads were identified in the DISIS-2016-001 Group 00 and Group 1, and DISIS-2016-002 Group 1 models as shown in Table 3-5, Table 3-6, and Table 3-7 respectively, however the TDF values were less than 20% and as such no mitigation was recommended for these overloads.

Table 3-5: GEN-2016-045 & GEN-2016-057 MRIS New Impacts DISIS-2016-001 Group 00

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%Loading)	Contingency	MRIS Modification (%Loading)	Mitigation
511481[WEATHER2 69.000] to 511517[THOMAST2 69.000] CKT 1	39	99.9	511484[CLINTJC2 69.000] to 511485[CLINTJC4 138.00] to 511499[CLINT1-1 13.800] CKT 1	100.4	Mitigation Not Required (TDF < 20%)

Table 3-6: GEN-2016-045 & GEN-2016-057 MRIS New Impacts DISIS-2016-001 Group 1

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%Loading)	Contingency	MRIS Modification (%Loading)	Mitigation
523090[TEXAS_CNTY 3115.00] to 523093[HITCHLAND 3115.00] CKT 1	174.9	99.9	523090[TEXAS_CNTY 3115.00] to 523093[HITCHLAND 3115.00] CKT 2	100.1	Mitigation Not Required (TDF < 20%)

Table 3-7: GEN-2016-045 & GEN-2016-057 MRIS New Impacts DISIS-2016-002 Group 1

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%Loading)	Contingency	MRIS Modification (%Loading)	Mitigation
510948[EARLSBORO 4138.00] to 15055[MAUD 4 138.00] CKT 1	143	<99	515497[MATHWSN7 345.00] to 900001[TRAVERSE1 345.00] CKT 1	101.1	Mitigation Not Required (TDF < 20%)
520942[HM-BTTP2 69.000] to 521000[MORWODS2 69.000] CKT 1	27	99.6	520500[BEARCAT 138.00] to 520999[MOORLND4 138.00] CKT 1	100.2	Mitigation Not Required (TDF < 20%)

4.0 Reactive Power Analysis

The reactive power analysis, also known as the low-wind/no-wind condition analysis, was performed for GEN-2016-045 and GEN-2016-057 to determine the reactive power contribution from the projects' interconnection line and collector transformers and cables during low/no wind conditions while the projects are still connected to the grid and to size shunt reactors that would reduce the projects' reactive power contributions to the POI to approximately zero.

4.1 Methodology and Criteria

For the GEN-2016-045 and GEN-2016-057 projects, the generators were switched out of service while other collector system elements remained in-service. A shunt reactor was tested at the main collection substation 345 kV bus to set the MVAr flow into the POI to approximately zero while the GEN-2016-045 and GEN-2016-057 projects were offline.

4.2 Results

The results from the reactive power analysis showed that the GEN-2016-045 and GEN-2016-057 projects required approximately 115 MVAr for shunt reactance at the high side bus of the project substation, to reduce the POI MVAr to zero. This represents the contributions from the project collector systems.

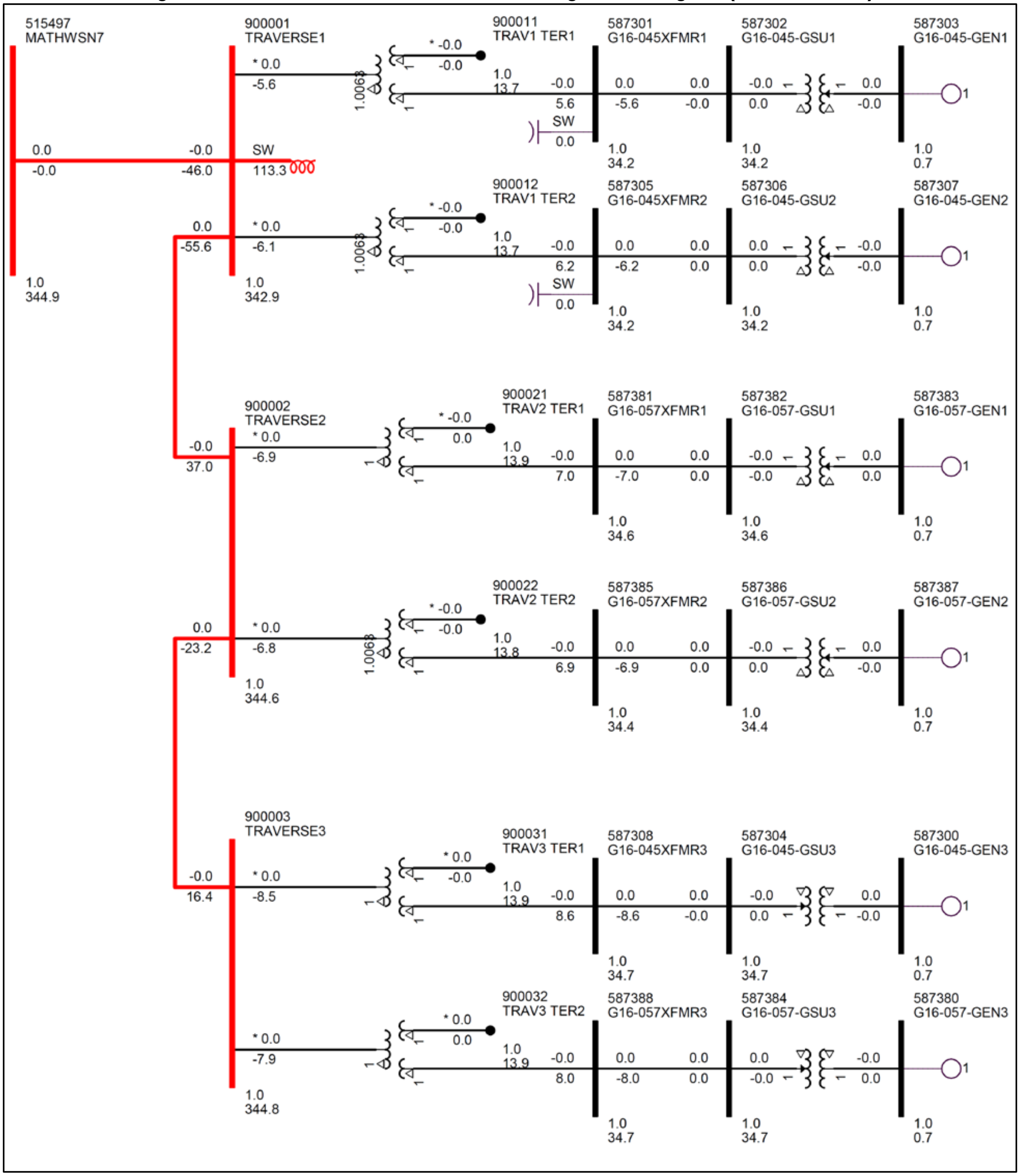
Table 4-1 shows the shunt reactor sizes determined for GEN-2016-045 and GEN-2016-057 in the three study models used in the assessment.

Table 4-1: Shunt Reactor Size for Low Wind Study

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)		
			17WP	18SP	26SP
GEN-2016-045 & GEN-2016-057	515497	Mathewson 7	114.7	115	115

Figure 4-1 illustrates the shunt reactor sizes required to reduce the POI MVAr flow to approximately zero. Reactive compensation can be provided either by discrete reactive devices or by the generator itself if it possesses that capability.

Figure 4-1: GEN-2016-045 & GEN-2016-057 Single Line Diagram (Shunt Reactor)



5.0 Short Circuit Analysis

A short-circuit study was performed on the power flow models for the 2018SP and 2026SP models for GEN-2016-045 and GEN-2016-057 using the modified study models. The detail 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 the project 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. The GEN-2016-045 and GEN-2016-057 POI bus fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 32.68 kA.

The maximum fault current calculated within 5 buses of the GEN-2016-045 and GEN-2016-057 POI was less than 50 kA and 52 kA for the 2018SP and 2026SP models respectively. The maximum increase in fault current for all buses evaluated was about 7.0% and 2.14 kA.

The bus locations with fault currents greater than 40 kA are highlighted in Appendix B.

Table 5-1: POI Short Circuit Results

Case	MRIS Current (kA)	Existing Current (kA)	Max kA Change	Max %Change
2018SP	32.68	30.54	2.14	7.0%
2026SP	32.65	30.51	2.14	7.0%

Table 5-2: 2018SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	10.6	0.00	-0.1%
138	49.9	0.41	0.9%
345	33.4	2.14	7.0%
Max	**49.9**	**2.14**	**7.0%**

Table 5-3: 2026SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	10.8	0.00	0.0%
138	51.2	0.41	0.9%
345	33.3	2.14	7.0%
Max	**51.2**	**2.14**	**7.0%**

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine changes and other modifications to the GEN-2016-045 and GEN-2016-057 projects. 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 D. The simulation plots can be found in Appendix E.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested 338 x GE 2.82MW + 18 x GE 2.5MW turbines for GEN-2016-045 and GEN-2016-057. This stability analysis was performed using PTI's PSS/E version 33.7 software.

The stability models were developed using the models from the DISIS-2016-002 ReStudy #1 (DISIS-2016-002-1) for Group 1 including network upgrades identified in that restudy. The modifications requested to projects GEN-2016-045 and GEN-2016-057 were used to create modified stability models for this impact study.

The modified power flow models and associated dynamics database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data. The modified dynamics model data for the DISIS-2016-002-1 (Group 1) request, GEN-2016-045 and GEN-2016-057 is provided in Appendix D.

During the fault simulations, the active power (PELEC), reactive power (QELEC) and terminal voltage (ETERM) were monitored for GEN-2016-045 and GEN-2016-057 and other equally and prior queued projects in Group 1. In addition, voltages of five (5) buses away from the POI of GEN-2016-045 and GEN-2016-057 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 selected the fault events simulated specifically for GEN-2016-045 and GEN-2016-057 in the DISIS-2016-002-1 Group 1 study and included additional faults based on the location of the point of interconnection. The new set of faults were simulated using the modified study models. The fault events include three phase faults with reclosing, stuck breaker, and prior outage events. Single-line-to-ground (SLG) fault impedance values were determined by applying a fault on the base case large enough to produce a 0.6 pu voltage value on the faulted bus. This SLG value was then used for the SLG faults.

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	Fault Descriptions
FLT01-3PH	3 phase fault on CIMARON7 345 kV (514901) to MATHWSN7 345 kV (515497) 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 reclose 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	3 phase fault on CIMARON7 345 kV (514901) to NORTWST7 345 kV (514880), 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 reclose 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	3 phase fault on CIMARON7 345 kV (514901) to MINCO 7 345 kV (514801), 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 reclose 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	3 phase fault on CIMARON7 345 kV (514901) to DRAPER 7 345 kV (514934), 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 reclose 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	3 phase fault on the CIMARON7 345 kV (514901) to CIMARON4 138 kV (514898) to CIMARO11 13.8 kV (515714) XFMR, near CIMARON7 345 kV. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT15-SB	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) - NORTWST7 (514880) d. CIMARON7 (514901) - DRAPER 7 (514934)
FLT16-SB	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) - MINCO 7 (514801) d. CIMARON7 345 kV (514901) / CIMARON4 138 kV (514898) / CIMARON11 13.8 kV (515714) transformer.
FLT17-SB	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) CKT 1 d. CIMARON7 (514901) - NORTWST7 (514880)
FLT18-SB	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) CKT 1 d. CIMARON7 (514901) - MINCO 7 (514801)
FLT19-SB	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) CKT 1 d. CIMARON7 (514901) - DRAPER (514934)

Table 6-1 continued

Fault ID	Fault Descriptions
FLT20-SB	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), CKT 1 d. CIMARON7 345 kV (514901) / CIMARON4 138 kV (514898) / CIMARON11 13.8 kV (515714) transformer.
FLT39-3PH	3 phase fault on G16-003-TAP 345 kV (560071) to WWRDEHV7 345 kV (515375) CKT 1, near G16-003-TAP. a. Apply fault at the G16-003-TAP 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT43-3PH	3 phase fault on WWRDEHV7 345 kV (515375) to THISTLE7 345 kV (539801) CKT1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT44-3PH	3 phase fault on WWRDEHV7 345 kV (515375) to BORDER 7 345 kV (515458), near WWRDEHV7. a. Apply fault at the WWRDEHV7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT45-3PH	3 phase fault on WWRDEHV7 345 kV (515375) to WWRDEHV4 138 kV (515376) to WWDEHV31 13.8 kV (515795) XFMR, near WWRDEHV7 345 kV. a. Apply fault at the WWRDEHV7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT48-SB	Stuck Breaker at WWRDEHV7 (515375) a. Apply single phase fault at WWRDEHV7 bus. b. Clear fault after 16 cycles and trip the following elements c. WWRDEHV7 (515375) - THISTLE7 (539801) CKT 1 d. WWRDEHV7 345kV (515375) / WWRDEHV4 138 kV (515376) / WWDEHV31 13.8 kV (515795) transformer
FLT65-3PH	3 phase fault on MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) CKT1, 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 reclose 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	3 phase fault on MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880), 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 reclose 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	3 phase fault on NORTWST7 345 kV (514880) to NORTWST4 138 kV (514879) to NORTWS41 13.8 kV (514885) XFMR, 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	3 phase fault on NORTWST7 345 kV (514880) to ARCADIA7 345 kV (514908), 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 reclose 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	3 phase fault on NORTWST7 345 kV (514880) to SPRNGCK7 345 kV (514881), 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 reclose 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	Fault Descriptions
FLT73-SB	Stuck Breaker at MATHWSN7 (515497) a. Apply single phase fault at MATHWSN7. b. Clear fault after 16 cycles and trip the following elements c. MATHWSN7 (515497) - NORTWST7 (514880) d. MATHWSN7 (515497) - CIMARON7 (514901), CKT 1
FLT75-3PH	3 phase fault on CIMARON7 345 kV (514901) to MATHWSN7 345 kV (515497) 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 reclose 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-PO1	Prior Outage of CIMARON7 345 kV (514901) to NORTWST7 345 kV (514880) line 3 phase fault on CIMARON7 345 kV (514901) to DRAPER 7 345 kV (514934), 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 reclose 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	Prior Outage of CIMARON7 345 kV (514901) to MINCO 7 345 kV (514801) line 3 phase fault on the CIMARON7 345 kV (514901) to CIMARON4 138 kV (514898) to CIMARO11 13.8 kV (515714) XFMR, near CIMARON7 345 kV. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT45-PO3	Prior Outage of WWRDEHV7 345 kV (515375) to THISTLE7 345 kV (539801) CKT1 line 3 phase fault on WWRDEHV7 345 kV (515375) to WWRDEHV4 138 kV (515376) to WWDEHV31 13.8 kV (515795) XFMR, near WWRDEHV7 345 kV. a. Apply fault at the WWRDEHV7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT75-PO4	Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line 3 phase fault on CIMARON7 345 kV (514901) to MATHWSN7 345 kV (515497) 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 reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-3PH	3 phase fault on TATONGA7 345 kV (515407) to SLNGWND7 345 kV (515582), near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generator SELIG WTG1 (599059), generator SILNGWG1 (515587). c. Wait 20 cycles, and then reclose 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	3 phase fault on TATONGA7 345 kV (515407) to CRSRDSW7 345 kV (515448), near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generator CRSRD-WTG1 (599099) generator CRSRD-WTG2 (599101) and CRSRDX-WTG2 (599103). c. Wait 20 cycles, and then reclose 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	3 phase fault on TATONGA7 345 kV (515407) to WWRDEHV 345 kV (515375) CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9004-3PH	3 phase fault on TATONGA7 345 kV (515407) to GEN-2015-029 345 kV (584700), near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generator G15-029-GEN1 (584703). c. Wait 20 cycles, and then reclose 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	Fault Descriptions
FLT9005-3PH	3 phase fault on TATONGA7 345 kV (515407) to MAMTHPW7 345 kV (515585), near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generator MMTHPLN_GEN (599136). c. Wait 20 cycles, and then reclose 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	3 phase fault on WWRDEHV7 345 kV (515375) to G07621119-20 345 kV (515599), near WWRDEHV7. a. Apply fault at the WWRDEHV7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generators GW_WTG11 (585413), GW_WTG12 (585414), GW_WTG22 (585418), GW_WTG21 (585417), CB_WTG1 (585423), CB_WTG2 (585426), PC1_WTG2 (585436), PC2_WTG1 (585443) and PC2_WTG2 (585446). c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9007-3PH	3 phase fault on WWRDEHV7 345 kV (515375) to G16-003-TAP 345 kV (560071) CRT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	3 phase fault on WWRDEHV4 138 kV (515376) to IODINE-4 138 kV (514796), near WWRDEHV4. a. Apply fault at the WWRDEHV4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	3 phase fault on WWRDEHV4 138 kV (515376) to WWDPST 4 138 kV (515425), near WWRDEHV4. a. Apply fault at the WWRDEHV4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9010-3PH	3 phase fault on WWRDEHV4 138 kV (515376) to KEENAN 4 138 kV (515394), near WWRDEHV4. a. Apply fault at the WWRDEHV4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generators KEENAN-WTG1 (599064) and KEENAN-WTG2 (599065) c. Wait 20 cycles, and then reclose 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	3 phase fault on WWRDEHV4 138 kV (515376) to OUSPRT 4 138 kV (515398), near WWRDEHV4. a. Apply fault at the WWRDEHV4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generator OUSPRT-WTG1 (599081). c. Wait 20 cycles, and then reclose 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	3 phase fault on MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875), 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 reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9018-3PH	3 phase fault on REDNGTN7 345 kV (515875) to WOODRNG7 345 kV (514715), near REDNGTN7. a. Apply fault at the REDNGTN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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	3 phase fault on REDNGTN7 345 kV (515875) to REDDIRT7 345 kV (515877), near REDNGTN7. a. Apply fault at the REDNGTN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generator RDDRTG11 (515882), RDDRTG21 (515883). c. Wait 20 cycles, and then reclose 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	
FLT9020-3PH	3 phase fault on WOODRNG7 345 kV (514715) to HUNTERS7 345 kV (515476), near WOODRNG7. a. Apply fault at the WOODRNG7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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	3 phase fault on the WOODRNG7 345 kV (514715) to WOODRNG4 138 kV (514714) to WOODRNG1 13.8 kV (515770) XFMR, near WOODRNG7 345 kV. a. Apply fault at the WOODRNG7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9022-3PH	3 phase fault on WOODRNG7 345 kV (514715) to G16-061-TAP 345 kV (560084), near WOODRNG7. a. Apply fault at the WOODRNG7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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	3 phase fault on WOODRNG7 345 kV (514715) to GEN-2016-068 345 kV (587460), near WOODRNG7. a. Apply fault at the WOODRNG7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generators G16-068-GEN1 (587463) and G16-068-GEN1 (587466). c. Wait 20 cycles, and then reclose 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	3 phase fault on WOODRNG7 345 kV (514715) to GEN-2016-128 345 kV (588190), near WOODRNG7. a. Apply fault at the WOODRNG7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generator G16-128-GEN1 (588193). c. Wait 20 cycles, and then reclose 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	3 phase fault on CIMARON7 345 kV (514901) to FSHRTAP7 345 kV (515610), near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generators KNGFSHR-GEN1 (599122), KNGFSHR-GEN2 (599124), CANDIAN_WTG1 (599114) and CANDIAN_WTG2 (599116). c. Wait 20 cycles, and then reclose 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	3 phase fault on FSHRTAP7 345 kV (515610) to CANADN7 345 kV (515605), 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) and CANDIAN_WTG2 (599116). c. Wait 20 cycles, and then reclose 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	3 phase fault on FSHRTAP7 345 kV (515610) to KNGFSHR7 345 kV (515600), 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) and KNGFSHR-GEN2 (599124). c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9028-3PH	3 phase fault on MINCO 7 345 kV (514801) to GRACMNT7 345 kV (515800), 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 reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9029-3PH	3 phase fault on MINCO 7 345 kV (514801) to MNCWND37 345 kV (515549), 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 MINCO-WTG3 (599117), G14-056-GEN2 (584064), MNCO4G11 (515943), G15-057-GEN2 (584954), G15-057-GEN1 (584953) and G15-057-GEN3 (584955). c. Wait 20 cycles, and then reclose 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	Fault Descriptions
FLT9030-3PH	3 phase fault on MINCO 7 345 kV (514801) to MCNOWND7 345 kV (515444), 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 MINCO-WTG1 (599062). c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9031-3PH	3 phase fault on the DRAPER 7 345 kV (514934) to DRAPER 4 138 kV (514933) to DRAPER21 13.8 kV (515792) XFMR, 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.
FLT9032-3PH	3 phase fault on DRAPER 7 345 kV (514934) to SEMINOL7 345 kV (515045) CRT 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 reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9033-3PH	3 phase fault on DRAPER 4 138 kV (514933) to GM 4 138 kV (514961), near DRAPER 4. a. Apply fault at the DRAPER 4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9034-3PH	3 phase fault on DRAPER 4 138 kV (514933) to BARNES 4 138 kV (515003), near DRAPER 4. a. Apply fault at the DRAPER 4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9035-3PH	3 phase fault on DRAPER 4 138 kV (514933) to SOONRTP4 138 kV (514949), near DRAPER 4. a. Apply fault at the DRAPER 4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9036-3PH	3 phase fault on DRAPER 4 138 kV (514933) to MIDWEST4 138 kV (514946), near DRAPER 4. a. Apply fault at the DRAPER 4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9037-3PH	3 phase fault on NORTWST4 138 kV (514879) to BRADEN 4 138 kV (514854), near NORTWST4. a. Apply fault at the NORTWST4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9038-3PH	3 phase fault on NORTWST4 138 kV (514879) to LNEOAK 4 138 kV (514873), near NORTWST4. a. Apply fault at the NORTWST4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9039-3PH	3 phase fault on NORTWST4 138 kV (514879) to PIEDMNT4 138 kV (514864), near NORTWST4. a. Apply fault at the NORTWST4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9040-3PH	3 phase fault on NORTWST4 138 kV (514879) to KETCHTP4 138 kV (514828), near NORTWST4. a. Apply fault at the NORTWST4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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	Fault Descriptions
FLT9041-3PH	3 phase fault on SPRNGCK7 345 kV (514881) to G16-100-TAP 345 kV (587804), near SPRNGCK7. a. Apply fault at the SPRNGCK7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9042-3PH	3 phase fault on SPRNGCK7 345 kV (514881) to SPGCK1&2 13.8 kV (514882) XFMR, near SPRNGCK7 345 kV. a. Apply fault at the SPRNGCK7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9043-3PH	3 phase fault on WOODRNG4 138 kV (514714) to WAUKOTP4 138 kV (514711), near WOODRNG4. a. Apply fault at the WOODRNG4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9044-3PH	3 phase fault on WOODRNG4 138 kV (514714) to OTTER 138 kV (514708), near WOODRNG4. a. Apply fault at the WOODRNG4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9045-3PH	3 phase fault on WOODRNG4 138 kV (514714) to MARSHL 4 138 kV (514733), near WOODRNG4. a. Apply fault at the WOODRNG4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9046-3PH	3 phase fault on WOODRNG4 138 kV (514714) to FRMNTAP4 138 kV (514709), near WOODRNG4. a. Apply fault at the WOODRNG4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9047-3PH	3 phase fault on CIMARON4 138 kV (514898) to CZECHAL4 138 kV (514894), 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 reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9048-3PH	3 phase fault on CIMARON4 138 kV (514898) to SARA 4 138 kV (514895), 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 reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9049-3PH	3 phase fault on CIMARON4 138 kV (514898) to TUTCONT4 138 kV (511425), 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 reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9050-3PH	3 phase fault on CIMARON4 138 kV (514898) to HAYMAKR4 138 kV (514863), 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 reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9051-3PH	3 phase fault on CIMARON4 138 kV (514898) to EL-RENO4 138 kV (514819), 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 reclose 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	Fault Descriptions
FLT9052-3PH	3 phase fault on CIMARON4 138 kV (514898) to JENSENT4 138 kV (514820), 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 reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9053-3PH	3 phase fault on CZECHAL4 138 kV (514894) to XEROX 4 138 kV (514893), near CZECHAL4. a. Apply fault at the CZECHAL4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9054-3PH	3 phase fault on SARA 4 138 kV (514895) to STHLAKE4 138 kV (515481) (514902 for 17W), near SARA 4. a. Apply fault at the SARA 4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9055-3PH	3 phase fault on TUTCONT4 138 kV (511425) to T-CONCO4 138 kV (511424), near TUTCONT4. a. Apply fault at the TUTCONT4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9056-3PH	3 phase fault on TUTCONT4 138 kV (511425) to TUTTLE4 138 kV (511501), near TUTCONT4. a. Apply fault at the TUTCONT4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9057-3PH	3 phase fault on HAYMAKR4 138 kV (514863) to DVISION4 138 kV (514853), near HAYMAKR4. a. Apply fault at the HAYMAKR4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9058-3PH	3 phase fault on EL-RENO4 138 kV (514819) to ELRENO2 69 kV (514818) to EL RENO1 13.2 kV (515722) XFMR, near EL-RENO4 138 kV. a. Apply fault at the EL-RENO4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9059-3PH	3 phase fault on JENSENT4 138 kV (514820) to EL-RENO4 138 kV (514819), near JENSENT4. a. Apply fault at the JENSENT4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9060-3PH	3 phase fault on JENSENT4 138 kV (514820) to JENSEN4 138 kV (514821), near JENSENT4. a. Apply fault at the JENSENT4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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-PO4	Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line 3 phase fault on CIMARON7 345 kV (514901) to NORTWST7 345 kV (514880), 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 reclose 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-PO4	Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line 3 phase fault on CIMARON7 345 kV (514901) to MINCO 7 345 kV (514801), 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 reclose 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	Fault Descriptions
FLT04-PO4	Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line 3 phase fault on CIMARON7 345 kV (514901) to DRAPER 7 345 kV (514934), 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 reclose 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	Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line 3 phase fault on the CIMARON7 345 kV (514901) to CIMARON4 138 kV (514898) to CIMARO11 13.8 kV (515714) XFMR, near CIMARON7 345 kV. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9025-PO4	Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line 3 phase fault on CIMARON7 345 kV (514901) to FSHRTAP7 345 kV (515610), near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generators KNGFSHR-GEN1 (599122), KNGFSHR-GEN2 (599124), CANDIAN_WTG1 (599114) and CANDIAN_WTG2 (599116). c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-PO4	Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line 3 phase fault on TATONGA7 345 kV (515407) to SLNGWND7 345 kV (515582), near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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-PO4	Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line 3 phase fault on TATONGA7 345 kV (515407) to CRSRDSW7 345 kV (515448), near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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-PO4	Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line 3 phase fault on TATONGA7 345 kV (515407) to WWRDEHV 345 kV (515375) CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9004-PO4	Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line 3 phase fault on TATONGA7 345 kV (515407) to GEN-2015-029 345 kV (584700), near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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-PO4	Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line 3 phase fault on TATONGA7 345 kV (515407) to MAMTHPW7 345 kV (515585), near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9018-PO4	Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line 3 phase fault on REDNGTN7 345 kV (514875) to WOODRNG7 345 kV (514715), near REDNGTN7. a. Apply fault at the REDNGTN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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-PO4	Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line 3 phase fault on REDNGTN7 345 kV (514875) to REDDIRT7 345 kV (515877), near REDNGTN7. a. Apply fault at the REDNGTN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generator RDDRTG11 (515882), RDDRTG21 (515883). c. Wait 20 cycles, and then reclose 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	Fault Descriptions
FLT02-PO5	Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) CRT 1 line 3 phase fault on CIMARON7 345 kV (514901) to NORTWST7 345 kV (514880), 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 reclose 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-PO5	Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) CRT 1 line 3 phase fault on CIMARON7 345 kV (514901) to MINCO 7 345 kV (514801), 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 reclose 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-PO5	Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) CRT 1 line 3 phase fault on CIMARON7 345 kV (514901) to DRAPER 7 345 kV (514934), 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 reclose 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-PO5	Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) CRT 1 line 3 phase fault on the CIMARON7 345 kV (514901) to CIMARON4 138 kV (514898) to CIMARO11 13.8 kV (515714) XFMR, near CIMARON7 345 kV. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9025-PO5	Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) CRT 1 line 3 phase fault on CIMARON7 345 kV (514901) to FSHRTAP7 345 kV (515610), near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generators KNGFSHR-GEN1 (599122), KNGFSHR-GEN2 (599124), CANDIAN_WTG1 (599114) and CANDIAN_WTG2 (599116). c. Wait 20 cycles, and then reclose 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-PO5	Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) CRT 1 line 3 phase fault on NORTWST7 345 kV (514880) to NORTWST4 138 kV (514879) to NORTWS41 13.8 kV (514885) XFMR, 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-PO5	Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) CRT 1 line 3 phase fault on NORTWST7 345 kV (514880) to ARCADIA7 345 kV (514908), 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 reclose 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-PO5	Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) CRT 1 line 3 phase fault on NORTWST7 345 kV (514880) to SPRNGCK7 345 kV (514881), 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 reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9018-PO5	Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) CRT 1 line 3 phase fault on REDNGTN7 345 kV (514875) to WOODRNG7 345 kV (514715), near REDNGTN7. a. Apply fault at the REDNGTN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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-PO5	Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) CRT 1 line 3 phase fault on REDNGTN7 345 kV (514875) to REDDIRT7 345 kV (515877), near REDNGTN7. a. Apply fault at the REDNGTN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generator RDDRTG11 (515882), RDDRTG21 (515883). c. Wait 20 cycles, and then reclose 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	Fault Descriptions
FLT02-PO6	Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line 3 phase fault on CIMARON7 345 kV (514901) to NORTWST7 345 kV (514880), 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 reclose 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-PO6	Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line 3 phase fault on CIMARON7 345 kV (514901) to MINCO 7 345 kV (514801), 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 reclose 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-PO6	Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line 3 phase fault on CIMARON7 345 kV (514901) to DRAPER 7 345 kV (514934), 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 reclose 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-PO6	Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line 3 phase fault on the CIMARON7 345 kV (514901) to CIMARON4 138 kV (514898) to CIMARO11 13.8 kV (515714) XFMR, near CIMARON7 345 kV. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9025-PO6	Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line 3 phase fault on CIMARON7 345 kV (514901) to FSHRTAP7 345 kV (515610), near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generators KNGFSHR-GEN1 (599122), KNGFSHR-GEN2 (599124), CANDIAN_WTG1 (599114) and CANDIAN_WTG2 (599116). c. Wait 20 cycles, and then reclose 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-PO6	Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line 3 phase fault on NORTWST7 345 kV (514880) to NORTWST4 138 kV (514879) to NORTWS41 13.8 kV (514885) XFMR, 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-PO6	Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line 3 phase fault on NORTWST7 345 kV (514880) to ARCADIA7 345 kV (514908), 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 reclose 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-PO6	Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line 3 phase fault on NORTWST7 345 kV (514880) to SPRNGCK7 345 kV (514881), 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 reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-PO6	Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line 3 phase fault on TATONGA7 345 kV (515407) to SLNGWND7 345 kV (515582), near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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-PO6	Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line 3 phase fault on TATONGA7 345 kV (515407) to CRSRDSW7 345 kV (515448), near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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	Fault Descriptions
FLT9003-PO6	Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line 3 phase fault on TATONGA7 345 kV (515407) to WWRDEHV 345 kV (515375) CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9004-PO6	Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line 3 phase fault on TATONGA7 345 kV (515407) to GEN-2015-029 345 kV (584700), near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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-PO6	Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line 3 phase fault on TATONGA7 345 kV (515407) to MAMTHPW7 345 kV (515585), near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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-PO7	Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) CRT 1 line 3 phase fault on NORTWST7 345 kV (514880) to NORTWST4 138 kV (514879) to NORTWS41 13.8 kV (514885) XFMR, 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-PO7	Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) CRT 1 line 3 phase fault on NORTWST7 345 kV (514880) to ARCADIA7 345 kV (514908), 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 reclose 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-PO7	Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) CRT 1 line 3 phase fault on NORTWST7 345 kV (514880) to SPRNGCK7 345 kV (514881), 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 reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-PO7	Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) CRT 1 line 3 phase fault on TATONGA7 345 kV (515407) to SLNGWND7 345 kV (515582), near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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-PO7	Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) CRT 1 line 3 phase fault on TATONGA7 345 kV (515407) to CRSRDSW7 345 kV (515448), near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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-PO7	Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) CRT 1 line 3 phase fault on TATONGA7 345 kV (515407) to WWRDEHV 345 kV (515375) CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9004-PO7	Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) CRT 1 line 3 phase fault on TATONGA7 345 kV (515407) to GEN-2015-029 345 kV (584700), near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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	Fault Descriptions
FLT9005-PO7	Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) CRT 1 line 3 phase fault on TATONGA7 345 kV (515407) to MAMTHPW7 345 kV (515585), near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9018-PO7	Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) CRT 1 line 3 phase fault on REDNGTN7 345 kV (514875) to WOODRNG7 345 kV (514715), near REDNGTN7. a. Apply fault at the REDNGTN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose 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-PO7	Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) CRT 1 line 3 phase fault on REDNGTN7 345 kV (514875) to REDDIRT7 345 kV (515877), near REDNGTN7. a. Apply fault at the REDNGTN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generator RDDRTG11 (515882), RDDRTG21 (515883). c. Wait 20 cycles, and then reclose 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	Stuck Breaker at TATONGA7 (515407) a. Apply single phase fault at TATONGA7 bus. b. Clear fault after 16 cycles and trip the following elements. Trip generator MMTHPLN_GEN (599136) c. TATONGA7 (515407) - MATHWSN7 (515497) CRT 1 d. TATONGA7 (515407) - MAMTHPW7 345 kV (515585)
FLT1002-SB	Stuck Breaker at REDNGTN7 (515875) a. Apply single phase fault at REDNGTN7 bus. b. Clear fault after 16 cycles and trip the following elements c. REDNGTN7 (515875) - MATHWSN7 (515497) d. REDNGTN7 (515875) - REDDIRT7 (515877)
FLT1003-SB	Stuck Breaker at NORTWST7 (514880) a. Apply single phase fault at NORTWST7 bus. b. Clear fault after 16 cycles and trip the following elements c. NORTWST7 (514880) - MATHWSN7 (515497) d. NORTWST7 (514880) / NORTWST4 138 kV (514879) / NORTWS31 13.8 kV (515743) transformer

6.3 Results

There were no damping or voltage recovery violations observed during the simulations and the system returned to stable conditions for all the simualted faults that were associated with the modification request.

Table 6-2 shows the results of the fault events simulated for each of the models. The associated stability plots are provided in Appendix E. Additionally, the project wind farm 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.

Table 6-2: GEN-2016-045 & GEN-2016-057 Dynamic Stability Results

Fault ID	17W			18S			26S		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	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
FLT15-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT16-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT17-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT18-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT19-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT20-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT39-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT43-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT44-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT45-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT48-SB	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
FLT73-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT75-3PH	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
FLT1003-SB	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
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	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
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

Table 6-2 continued

Fault ID	17W			18S			26S		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	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
FLT9033-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9034-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9035-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9036-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9037-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9038-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9039-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9040-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9041-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9042-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9043-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9044-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9045-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9046-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9047-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9048-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9049-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9050-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9051-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9052-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9053-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9054-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9055-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9056-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9057-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9058-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9059-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9060-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-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
FLT9025-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	17W			18S			26S		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT68-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT69-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT70-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT68-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT69-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT70-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT68-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT69-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT70-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-PO7	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
FLT45-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT75-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

7.0 Conclusions

The Interconnection Customer requested a Modification Request Impact Study to assess the impact of the turbine and facility changes to GEN-2016-045 and GEN-2016-057 which have the same point of interconnection at the Mathewson 345kV substation. The changes to GEN-2016-045 and GEN-2016-057 include a new configuration with a total of 338 x GE 2.82MW + 18 x GE 2.5MW wind turbines for a total capacity of 998.18 MW In addition, the modification request included changes to the generation interconnection lines, collection systems and the generator substation transformers.

The power flow analysis showed that the high voltages and loading violations previously identified in the DISIS-2016-001-1 report were not observed in the modification request study cases because of changes to the generation interconnection line and also because the modification request cases used in this study included previously identified mitigation upgrades:

1. Cimarron – Draper Lake 345 kV Line Upgrade (SPP-NTC-200416)
2. DeGrasse 345/138kV Project (SPP-NTC-200418 & 200419)

The modification request did cause a slight increase on Dover – Henessey 138 kV line overload which was previously attributed to the GEN-2016-118 project in the DISIS-2016-002 report. However, it is confirmed that the DISIS-2016-002 assigned mitigation for the Dover – Henessey 138 kV line will be sufficient. The modification did not cause additional thermal or voltage constraints with a relevant TDF (>3% for N-0, or >20% for N-1).

A power factor analysis was not performed as there was no change in the point of interconnection for GEN-2016-045 and GEN-2016-057.

The results of the reactive power analysis, also known as the low-wind/no-wind condition analysis, performed using all three models showed that the combined GEN-2016-045 and GEN-2016-057 projects may require a 115 MVAr sized shunt reactor on the 345 kV bus of the main project substation. The shunt reactor is needed to reduce the reactive power flow at the POI to approximately zero during low/no wind conditions while the generation interconnection project remains connected to the grid.

The results from short circuit analysis showed that the maximum change in the fault currents in the immediate systems at or near GEN-2016-045 and GEN-2016-057 was 2.14 kA. The largest fault current calculated was below 50 kA and 52 kA in the 2018SP and 2026SP models respectively. The GEN-2016-045 and GEN-2016-057 POI bus had a maximum fault current of 32.68 kA.

The results of the dynamic stability analysis showed that there were no damping or voltage recovery violations observed during the simulations and the system returned to stable conditions for all the simulated faults. Additionally, the project generators were 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 results of this Study show that the GEN-2016-045 and GEN-2016-057 Modification Request does not constitute a material modification.