Report on

GEN-2010-014 and GEN-2011-022 Modification Request Impact Study

Revision R1 **July 11, 2022**

Submitted to
Southwest Power Pool

anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
06/23/2022	Aneden Consulting	Initial Report Issued

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2010-014 and GEN-2011-022, two active Generation Interconnection Requests (GIR) with a point of interconnection (POI) at the Hitchland 345 kV Substation.

The GEN-2010-014 and GEN-2011-022 projects interconnect in the Southwestern Public Service Company (SWPS) control area with a total combined size of 671.6 MW controlled to the allowed amount of 657.8 MW shown in Table ES-1 below. This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2010-014 and GEN-2011-022 to a turbine configuration of 126 x GE 2.82 MW (355.32 MW) and 108 x GE 2.82 MW (304.56 MW) respectively for a total capacity of 659.88 MW. This combined generating capacity for GEN-2010-014 and GEN-2011-022 (659.88 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, 657.8 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line, reactive power devices, and main substation transformers. The existing and modified configurations for GEN-2010-014 and GEN-2011-022 are shown in Table ES-2 and Table ES-3 respectively.

Table ES-1: GEN-2010-014 & GEN-2011-022 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	Interconnection Queue Capacity (MW)
GEN-2010-014	Hitchland 345 kV (523097)	159 x Siemens 2.3 MW	358.8 (365.7 Installed)
GEN-2011-022	Hitchland 345 kV (523097)	133 X Siemens 2.3 MW	299 (305.9 Installed)
		Total Combined Capacity	657.8 (671.6 Installed)

Table ES-2: GEN-2010-014 Modification Request

<table>
<tr><th>Facility</th><th colspan="2">Existing Configuration</th><th colspan="4">Modification Configuration</th></tr>
<tr><td>Point of Interconnection</td><td colspan="2">Hitchland 345 kV (523097)</td><td colspan="4">Hitchland 345 kV (523097)</td></tr>
<tr><td>Configuration/Capacity</td><td colspan="2">159 x Siemens 2.3 MW = 365.7 MW
PPC to limit POI to 358.8 MW</td><td colspan="4">126 x GE 2.82 MW = 355.32 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td colspan="2"><u>Line shared with GEN-2011-022:</u>
Length = 15 miles
R = 0.000735 pu
X = 0.007485 pu
B = 0.126000 pu
Rating MVA = 1084 MVA</td><td colspan="4"><u>Line shared with GEN-2011-022:</u>
Length = 13.13 miles
R = 0.000430 pu
X = 0.006100 pu
B = 0.120700 pu
Rating MVA = 1084 MVA</td></tr>
<tr><td>Main Substation Transformer[1]</td><td><u>Transformer T1:</u>
X = 8.497%,
R = 0.212%,
Winding MVA = 123 MVA,
Rating MVA = 205 MVA</td><td><u>Transformer T2:</u>
X = 8.497%,
R = 0.212%,
Winding MVA = 123 MVA,
Rating MVA = 205 MVA</td><td colspan="2"><u>Transformer T1:</u>
X = 8.709%, R = 0.158%,
Winding MVA = 120 MVA,
Rating MVA = 205 MVA</td><td colspan="2"><u>Transformer T2:</u>
X = 8.637%, R = 0.159%,
Winding MVA = 120 MVA,
Rating MVA = 205 MVA</td></tr>
<tr><td>Equivalent GSU Transformer[1]</td><td>Gen 1 Equivalent Qty: 80
X = 5.699%,
R = 0.76%,
Winding MVA = 192 MVA,
Rating MVA = 214.8 MVA</td><td>Gen 2 Equivalent Qty: 79
X = 5.699%,
R = 0.76%,
Winding MVA = 189.6 MVA,
Rating MVA = 212.1 MVA</td><td colspan="2">Gen 1 Equivalent Qty: 63
X = 5.762%, R = 0.571%,
Winding MVA = 176.4 MVA,
Rating MVA = 204.8 MVA</td><td colspan="2">Gen 2 Equivalent Qty: 63
X = 5.762%, R = 0.571%,
Winding MVA = 176.4 MVA,
Rating MVA = 204.8 MVA</td></tr>
<tr><td>Equivalent Collector Line[2]</td><td>R = 0.002185 pu
X = 0.003353 pu
B = 0.031257 pu</td><td>R = 0.002213 pu
X = 0.003390 pu
B = 0.030983 pu</td><td colspan="2">R = 0.006452 pu
X = 0.012510 pu
B = 0.112837 pu</td><td colspan="2">R = 0.007128 pu
X = 0.013853 pu
B = 0.122935 pu</td></tr>
<tr><td>Reactive Power Devices</td><td colspan="2">N/A</td><td colspan="4">1 x 20 MVAR 34.5 kV Capacitor Bank</td></tr>
<tr><td>Generator Dynamic Model[3] & Power Factor</td><td>80 x Siemens 2.3 MW (SWTGU2)[3] ±0.90</td><td>79 x Siemens 2.3 MW (SWTGU2)[3] ±0.90</td><td>40 x GE 2.82 MW (GEWTG0705)[3] ±0.90</td><td>23 x GE 2.82 MW (GEWTG0705)[3] ±0.87</td><td>44 x GE 2.82 MW (GEWTG0705)[3] ±0.90</td><td>19 x GE 2.82 MW (GEWTG0705)[3] ±0.87</td></tr>
</table>

1) X/R based on Winding MVA, 2) All pu are on 100 MVA Base 3) DYR stability model name

Table ES-3: GEN-2011-022 Modification Request

<table>
<tr><th>Facility</th><th colspan="2">Existing Configuration</th><th colspan="4">Modification Configuration</th></tr>
<tr><td>Point of Interconnection</td><td colspan="2">Hitchland 345 kV (523097)</td><td colspan="4">Hitchland 345 kV (523097)</td></tr>
<tr><td>Configuration/Capacity</td><td colspan="2">133 X Siemens 2.3 MW = 305.9 MW
PPC to limit POI to 299 MW</td><td colspan="4">108 x GE 2.82 MW = 304.56 MW
PPC to limit POI to 299 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td colspan="2"><u>Line shared with GEN-2010-014:</u>
Length = 15 miles
R = 0.000735 pu
X = 0.007485 pu
B = 0.126000 pu
Rating MVA = 1084 MVA</td><td colspan="4"><u>Line shared with GEN-2010-014:</u>
Length = 13.13 miles
R = 0.000430 pu
X = 0.006100 pu
B = 0.120700 pu
Rating MVA = 1084 MVA</td></tr>
<tr><td>Main Substation Transformer[1]</td><td><u>Transformer T1:</u>
X = 8.497%,
R = 0.212%,
Winding MVA = 102 MVA,
Rating MVA = 170 MVA</td><td><u>Transformer T2:</u>
X = 8.497%,
R = 0.212%,
Winding MVA = 102 MVA,
Rating MVA = 170 MVA</td><td colspan="2"><u>Transformer T3:</u>
X = 8.518%, R = 0.171%,
Winding MVA = 102 MVA,
Rating MVA = 170 MVA</td><td colspan="2"><u>Transformer T4:</u>
X = 8.497%, R = 0.170%,
Winding MVA = 102 MVA,
Rating MVA = 170 MVA</td></tr>
<tr><td>Equivalent GSU Transformer[1]</td><td>Gen 1 Equivalent Qty: 67
X = 5.699%,
R = 0.76%,
Winding MVA = 160.8 MVA,
Rating MVA = 179.9 MVA</td><td>Gen 2 Equivalent Qty: 66
X = 5.699%,
R = 0.76%,
Winding MVA = 158.4 MVA,
Rating MVA = 177.2 MVA</td><td colspan="2">Gen 1 Equivalent Qty: 54
X = 5.772%, R = 0.566%,
Winding MVA = 151.2 MVA,
Rating MVA = 175.5 MVA</td><td colspan="2">Gen 2 Equivalent Qty: 54
X = 5.772%, R = 0.566%,
Winding MVA = 151.2 MVA,
Rating MVA = 175.5 MVA</td></tr>
<tr><td>Equivalent Collector Line[2]</td><td>R = 0.002600 pu
X = 0.003995 pu
B = 0.026139 pu</td><td>R = 0.002629 pu
X = 0.004034 pu
B = 0.025865 pu</td><td colspan="2">R = 0.008434 pu
X = 0.016876 pu
B = 0.108377 pu</td><td colspan="2">R = 0.007500 pu
X = 0.014399 pu
B = 0.102018 pu</td></tr>
<tr><td>Generator Dynamic Model[3] & Power Factor</td><td>67 x Siemens 2.3 MW (SWTGU2)[3] ±0.90</td><td>66 x Siemens 2.3 MW (SWTGU2)[3] ±0.90</td><td>35 x GE 2.82 MW (GEWTG0705)[3] ±0.90</td><td>19 x GE 2.82 MW (GEWTG0705)[3] ±0.87</td><td>37 x GE 2.82 MW (GEWTG0705)[3] ±0.90</td><td>17 x GE 2.82 MW (GEWTG0705)[3] ±0.87</td></tr>
</table>

1) X/R based on Winding MVA, 2) All pu are on 100 MVA Base 3) DYR stability model name

SPP determined that power flow analysis should not be performed based on the POI MW injection decrease of 1.8% compared to the DISIS-2017-001 power flow models. However, SPP determined that the turbine change from Siemens to GE required short circuit and dynamic stability analyses.

The scope of this modification request study included charging current compensation analysis, short circuit analysis, and dynamic stability analysis.

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

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

All analyses were performed using the PTI PSS/E version 33 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak models showed that the GEN-2010-014 and GEN-2011-022 project needed 59.1 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 24.9 MVAr found for the existing GEN-2010-014 and GEN-2011-022 configuration found in the previous modification study[1]. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The results from the short circuit analysis with the updated configuration showed that the maximum GEN-2010-014 and GEN-2011-022 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2010-014 and GEN-2011-022 POI was no greater than 2.39 kA for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2010-014 and GEN-2011-022 generators online were below 30 kA for the 2021SP and 2028SP models.

The dynamic stability analysis was performed using PTI PSS/E version 33.10 software for the four modified study models, 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak. Up to 103 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

The results of the dynamic stability analysis showed that during numerous faults the MAJSTC Units (523941 & 523942) showed oscillations, and the OECGT Units (511939, 511940, 511942, & 511943) showed abnormal fluctuations in the post-contingency period. These issues were reported as base case issues in the DISIS-2017-001 stability report. As this was observed in both the DISIS and modification cases, it was not attributed to the GEN-2010-014 and GEN-2011-022 project.

After the loss of the Beaver County to Hitchland double circuit the GEN-2017-032 Unit (588753) showed reactive power drifting. This was observed in both the DISIS and modification cases, and was not attributed to the GEN-2010-014 and GEN-2011-022 project.

There were no damping or voltage recovery violations attributed to the GEN-2010-014 and GEN-2011-022 project observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

The requested modification has been determined by SPP to not be a Material Modification. The requested modification does not have a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date. As the requested modification places the generating capacity of the Interconnection Request at a higher amount than its Interconnection Service, the customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

[1] GEN-2010-014 and GEN-2011-022 Modification Request Impact Study – May 6, 2021

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

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

Nothing in this study should be construed as a guarantee of transmission service or delivery rights. If the customer wishes to obtain deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the customer.

1.0 Scope of Study

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2010-014 and GEN-2011-022. A Modification Request Impact Study is a generation interconnection study performed to evaluate the impacts of modifying the DISIS study assumptions. The determination of the required scope of the study is dependent upon the specific modification requested and how it may impact the results of the DISIS study. Impacting the DISIS results could potentially affect the cost or timing of any Interconnection Request with a later Queue priority date, deeming the requested modification a Material Modification. The criteria sections below include reasoning as to why an analysis was either included or excluded from the scope of study.

All analyses were performed using the PTI PSS/E version 33 software. The results of each analysis are presented in the following sections.

1.1 Power Flow Analysis

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

1.2 Dynamic Stability Analysis, Short Circuit Analysis

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

1.3 Charging Current Compensation Analysis

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

1.4 Study Limitations

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

2.0 Project and Modification Request

The GEN-2010-014 and GEN-2011-022 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the Hitchland 345 kV Substation. At the time of the posting of this report, GEN-2010-014 and GEN-2011-022 are active Interconnection Requests with queue statuses of “IA FULLY EXECUTED/ON SCHEDULE.” Both GEN-2010-014 and GEN-2011-022 are wind farms, and have maximum summer and winter queue capacities of 358.8 MW and 299 MW respectively with Energy Resource Interconnection Service (ERIS).

The GEN-2010-014 and GEN-2011-022 projects were originally studied as part the DISIS-2010-001 and DISIS-2011-001 studies respectively. The projects were last studied in a modification study[2] in May of 2021.

Figure 2-1 shows the power flow model single line diagram for the existing GEN-2010-014 and GEN-2011-022 configuration.

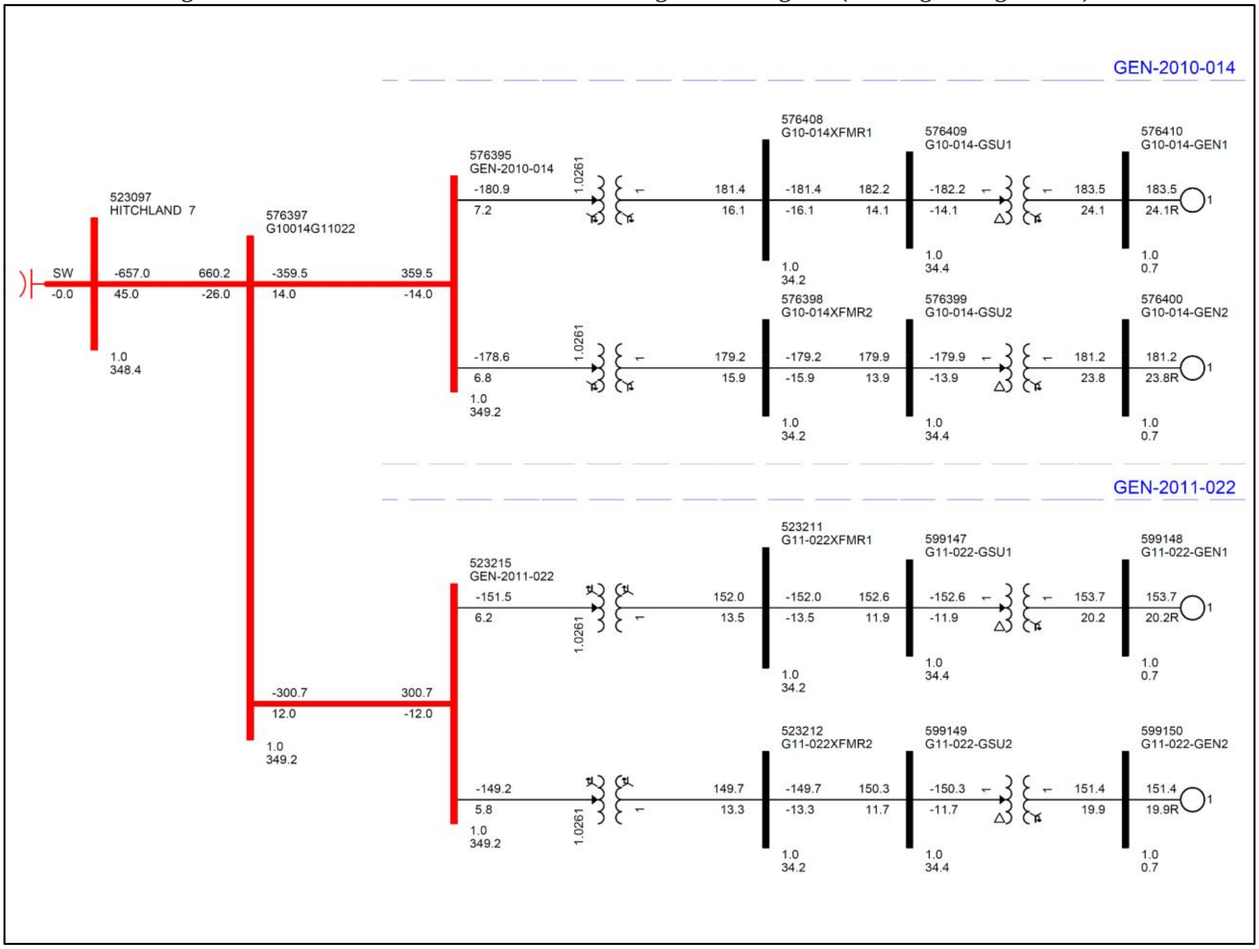
The GEN-2010-014 and GEN-2011-022 projects interconnect in the Southwestern Public Service Company (SWPS) control area with a total combined size of 671.6 MW controlled to the allowed amount of 657.8 MW shown in Table 2-1 below.

Table 2-1: GEN-2010-014 & GEN-2011-022 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	Interconnection Queue Capacity (MW)
GEN-2010-014	Hitchland 345 kV (523097)	159 x Siemens 2.3 MW	358.8 (365.7 Installed)
GEN-2011-022	Hitchland 345 kV (523097)	133 X Siemens 2.3 MW	299 (305.9 Installed)
		Total Combined Capacity	657.8 (671.6 Installed)

[2] GEN-2010-014 and GEN-2011-022 Modification Request Impact Study, May 6, 2021

Figure 2-1: GEN-2010-014 & GEN-2011-022 Single Line Diagram (Existing Configuration)



This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2010-014 and GEN-2011-022 to a turbine configuration of 126 x GE 2.82 MW (355.32 MW) and 108 x GE 2.82 MW (304.56 MW) respectively for a total capacity of 659.88 MW. This combined generating capacity for GEN-2010-014 and GEN-2011-022 (659.88 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, 657.8 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line, reactive power devices, and main substation transformers.

Figure 2-2shows the power flow model single line diagram for the GEN-2010-014 and GEN-2011-022 modification. The existing and modified configurations for GEN-2010-014 and GEN-2011-022 are shown in Table 2-2 and Table 2-3 respectively.

Figure 2-2: GEN-2010-014 & GEN-2011-022 Single Line Diagram (Modification Configuration)

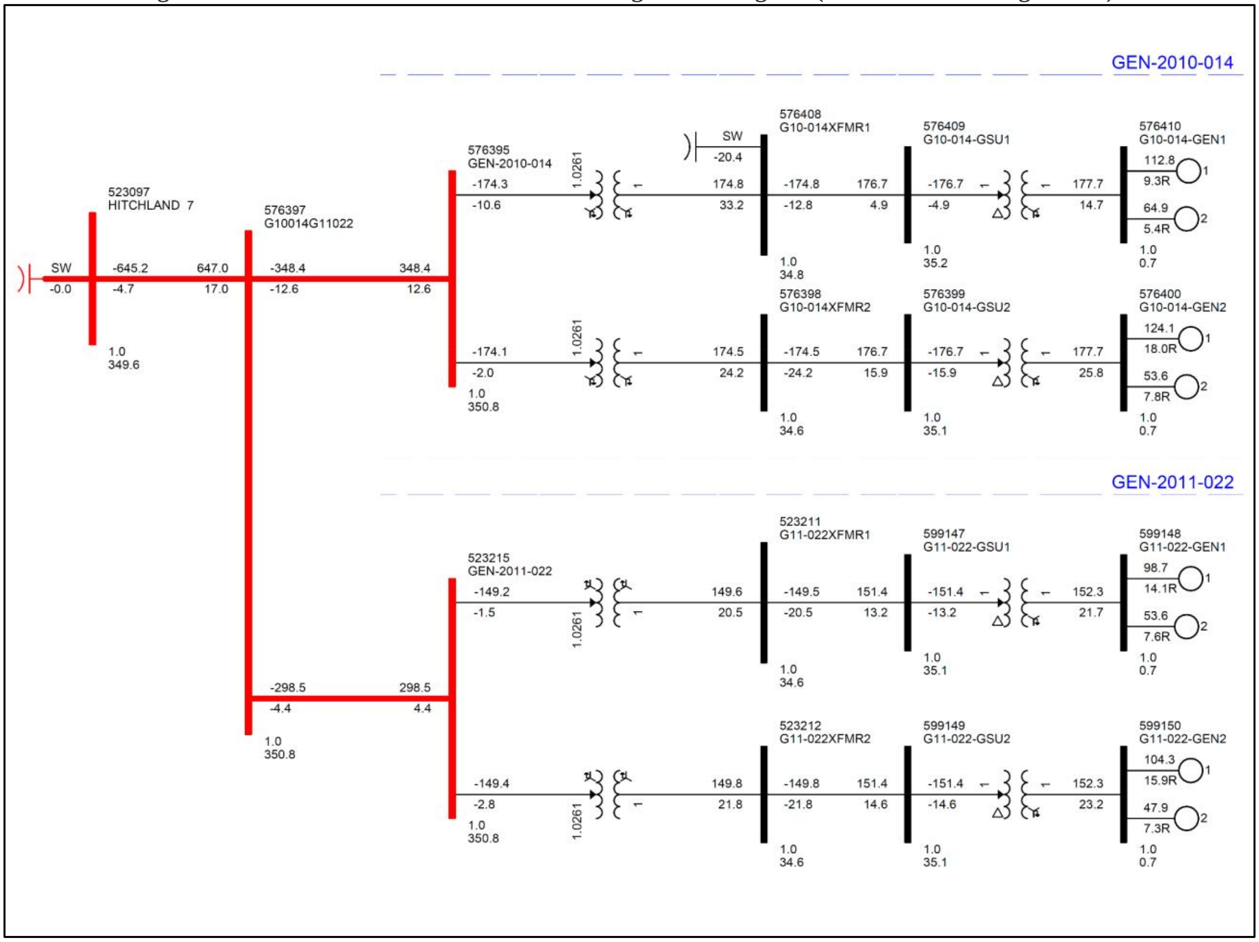


Table 2-2: GEN-2010-014 Modification Request

<table>
<tr><th>Facility</th><th colspan="2">Existing Configuration</th><th colspan="4">Modification Configuration</th></tr>
<tr><td>Point of Interconnection</td><td colspan="2">Hitchland 345 kV (523097)</td><td colspan="4">Hitchland 345 kV (523097)</td></tr>
<tr><td>Configuration/Capacity</td><td colspan="2">159 x Siemens 2.3 MW = 365.7 MW
PPC to limit POI to 358.8 MW</td><td colspan="4">126 x GE 2.82 MW = 355.32 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td colspan="2"><u>Line shared with GEN-2011-022:</u>
Length = 15 miles
R = 0.000735 pu
X = 0.007485 pu
B = 0.126000 pu
Rating MVA = 1084 MVA</td><td colspan="4"><u>Line shared with GEN-2011-022:</u>
Length = 13.13 miles
R = 0.000430 pu
X = 0.006100 pu
B = 0.120700 pu
Rating MVA = 1084 MVA</td></tr>
<tr><td>Main Substation Transformer[1]</td><td><u>Transformer T1:</u>
X = 8.497%,
R = 0.212%,
Winding MVA = 123 MVA,
Rating MVA = 205 MVA</td><td><u>Transformer T2:</u>
X = 8.497%,
R = 0.212%,
Winding MVA = 123 MVA,
Rating MVA = 205 MVA</td><td colspan="2"><u>Transformer T1:</u>
X = 8.709%, R = 0.158%,
Winding MVA = 120 MVA,
Rating MVA = 205 MVA</td><td colspan="2"><u>Transformer T2:</u>
X = 8.637%, R = 0.159%,
Winding MVA = 120 MVA,
Rating MVA = 205 MVA</td></tr>
<tr><td>Equivalent GSU Transformer[1]</td><td>Gen 1 Equivalent Qty: 80
X = 5.699%,
R = 0.76%,
Winding MVA = 192 MVA,
Rating MVA = 214.8 MVA</td><td>Gen 2 Equivalent Qty: 79
X = 5.699%,
R = 0.76%,
Winding MVA = 189.6 MVA,
Rating MVA = 212.1 MVA</td><td colspan="2">Gen 1 Equivalent Qty: 63
X = 5.762%, R = 0.571%,
Winding MVA = 176.4 MVA,
Rating MVA = 204.8 MVA</td><td colspan="2">Gen 2 Equivalent Qty: 63
X = 5.762%, R = 0.571%,
Winding MVA = 176.4 MVA,
Rating MVA = 204.8 MVA</td></tr>
<tr><td>Equivalent Collector Line[2]</td><td>R = 0.002185 pu
X = 0.003353 pu
B = 0.031257 pu</td><td>R = 0.002213 pu
X = 0.003390 pu
B = 0.030983 pu</td><td colspan="2">R = 0.006452 pu
X = 0.012510 pu
B = 0.112837 pu</td><td colspan="2">R = 0.007128 pu
X = 0.013853 pu
B = 0.122935 pu</td></tr>
<tr><td>Reactive Power Devices</td><td colspan="2">N/A</td><td colspan="4">1 x 20 MVAR 34.5 kV Capacitor Bank</td></tr>
<tr><td>Generator Dynamic Model[3] & Power Factor</td><td>80 x Siemens 2.3 MW (SWTGU2)[3] ±0.90</td><td>79 x Siemens 2.3 MW (SWTGU2)[3] ±0.90</td><td>40 x GE 2.82 MW (GEWTG0705)[3] ±0.90</td><td>23 x GE 2.82 MW (GEWTG0705)[3] ±0.87</td><td>44 x GE 2.82 MW (GEWTG0705)[3] ±0.90</td><td>19 x GE 2.82 MW (GEWTG0705)[3] ±0.87</td></tr>
</table>

1) X/R based on Winding MVA, 2) All pu are on 100 MVA Base 3) DYR stability model name

Table 2-3: GEN-2011-022 Modification Request

<table>
<tr><th>Facility</th><th colspan="2">Existing Configuration</th><th colspan="4">Modification Configuration</th></tr>
<tr><td>Point of Interconnection</td><td colspan="2">Hitchland 345 kV (523097)</td><td colspan="4">Hitchland 345 kV (523097)</td></tr>
<tr><td>Configuration/Capacity</td><td colspan="2">133 X Siemens 2.3 MW = 305.9 MW
PPC to limit POI to 299 MW</td><td colspan="4">108 x GE 2.82 MW = 304.56 MW
PPC to limit POI to 299 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td colspan="2"><u>Line shared with GEN-2010-014:</u>
Length = 15 miles
R = 0.000735 pu
X = 0.007485 pu
B = 0.126000 pu
Rating MVA = 1084 MVA</td><td colspan="4"><u>Line shared with GEN-2010-014:</u>
Length = 13.13 miles
R = 0.000430 pu
X = 0.006100 pu
B = 0.120700 pu
Rating MVA = 1084 MVA</td></tr>
<tr><td>Main Substation Transformer[1]</td><td><u>Transformer T1:</u>
X = 8.497%,
R = 0.212%,
Winding MVA = 102 MVA,
Rating MVA = 170 MVA</td><td><u>Transformer T2:</u>
X = 8.497%,
R = 0.212%,
Winding MVA = 102 MVA,
Rating MVA = 170 MVA</td><td colspan="2"><u>Transformer T3:</u>
X = 8.518%, R = 0.171%,
Winding MVA = 102 MVA,
Rating MVA = 170 MVA</td><td colspan="2"><u>Transformer T4:</u>
X = 8.497%, R = 0.170%,
Winding MVA = 102 MVA,
Rating MVA = 170 MVA</td></tr>
<tr><td>Equivalent GSU Transformer[1]</td><td>Gen 1 Equivalent Qty: 67
X = 5.699%,
R = 0.76%,
Winding MVA = 160.8 MVA,
Rating MVA = 179.9 MVA</td><td>Gen 2 Equivalent Qty: 66
X = 5.699%,
R = 0.76%,
Winding MVA = 158.4 MVA,
Rating MVA = 177.2 MVA</td><td colspan="2">Gen 1 Equivalent Qty: 54
X = 5.772%, R = 0.566%,
Winding MVA = 151.2 MVA,
Rating MVA = 175.5 MVA</td><td colspan="2">Gen 2 Equivalent Qty: 54
X = 5.772%, R = 0.566%,
Winding MVA = 151.2 MVA,
Rating MVA = 175.5 MVA</td></tr>
<tr><td>Equivalent Collector Line[2]</td><td>R = 0.002600 pu
X = 0.003995 pu
B = 0.026139 pu</td><td>R = 0.002629 pu
X = 0.004034 pu
B = 0.025865 pu</td><td colspan="2">R = 0.008434 pu
X = 0.016876 pu
B = 0.108377 pu</td><td colspan="2">R = 0.007500 pu
X = 0.014399 pu
B = 0.102018 pu</td></tr>
<tr><td>Generator Dynamic Model[3] & Power Factor</td><td>67 x Siemens 2.3 MW (SWTGU2)[3] ±0.90</td><td>66 x Siemens 2.3 MW (SWTGU2)[3] ±0.90</td><td>35 x GE 2.82 MW (GEWTG0705)[3] ±0.90</td><td>19 x GE 2.82 MW (GEWTG0705)[3] ±0.87</td><td>37 x GE 2.82 MW (GEWTG0705)[3] ±0.90</td><td>17 x GE 2.82 MW (GEWTG0705)[3] ±0.87</td></tr>
</table>

1) X/R based on Winding MVA, 2) All pu are on 100 MVA Base 3) DYR stability model name

3.0 Existing vs Modification Comparison

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

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

3.1 POI Injection Comparison

The real power injection at the POI was determined using PSS/E to compare the DISIS-2017-001 power flow configuration and the requested modification for GEN-2010-014 and GEN-2011-022. The percentage change in the POI injection was then evaluated. If the real power (MW) difference was determined to be significant (greater than 10%) power flow analysis would be performed to assess the impact of the modification request.

SPP determined that power flow analysis was not required due to the insignificant change, decrease of 1.8%, in the real power output at the POI between the studied DISIS-2017-001 power flow configuration and requested modification shown in Table 3-1.

Table 3-1: GEN-2010-014 & GEN-2011-022 POI Injection Comparison

Interconnection Request	Existing POI Injection (MW)	Modification POI Injection (MW)	POI Injection Difference %
GEN-2010-014 & GEN-2011-022	657.0	645.2	-1.80%

3.2 Turbine Parameters Comparison

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

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

3.3 Equivalent Impedance Comparison Calculation

As the turbine change determined that short circuit and dynamic stability analyses were required, an equivalent impedance comparison was not needed for the determination of the scope of the study.

4.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2010-014 and GEN-2011-022 to determine the capacitive charging effects under reduced generation conditions (unsuitable wind speeds, unsuitable solar irradiance, insufficient state of charge, idle conditions, curtailment, etc.) at the generation site and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

4.1 Methodology and Criteria

The GEN-2010-014 and GEN-2011-022 generators were switched out of service while other collection system elements remained in-service. A shunt reactor was tested at the project's collection substation 34.5 kV bus to offset the MVAr flow into the POI to approximately zero. The size of the shunt reactor is equivalent to the charging current value at unity voltage and the compensation provided is proportional to the voltage effects on the charging current (i.e., for voltages above unity, reactive compensation is greater than the size of the reactor).

4.2 Results

The results from the analysis showed that the combined GEN-2010-014 and GEN-2011-022 project needed approximately 59.1 MVAr of compensation at its collector substation, to reduce the POI MVAr to zero. This is an increase from the 24.9 MVAr found for the existing GEN-2010-014 and GEN-2011-022 configuration found in the previous modification study[3]. The final shunt reactor requirements for GEN-2010-014 and GEN-2011-022 are shown in Table 4-1. Figure 4-1 illustrates the shunt reactor size (shown in the red box) needed to reduce the POI MVAr to approximately zero with the updated configuration.

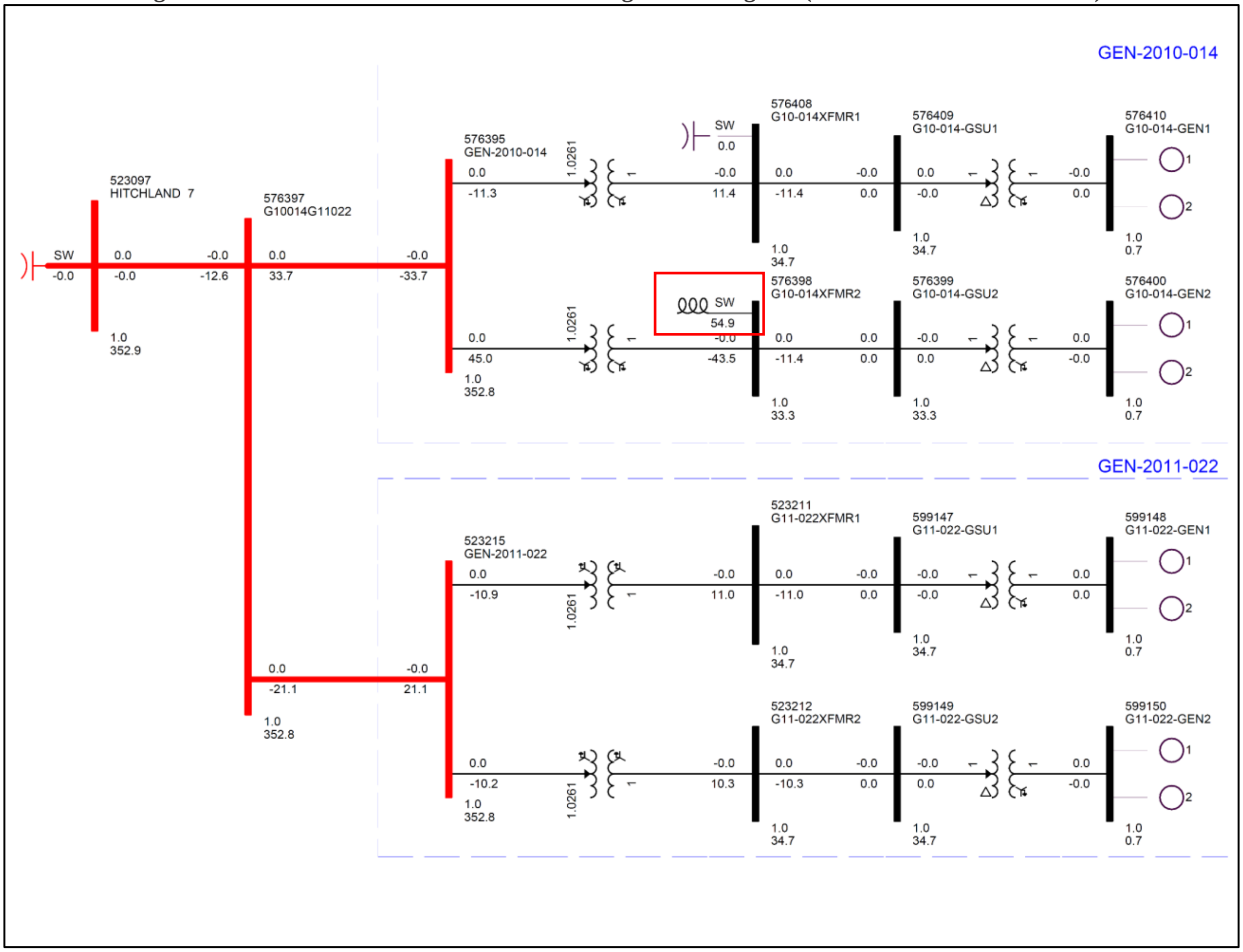
The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission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

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

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)			
			19WP	21LL	21SP	28SP
GEN-2010-014 & GEN-2011-022	523097	Hitchland 345 kV	59.1	59.1	59.1	59.1

[3] GEN-2010-014 and GEN-2011-022 Modification Request Impact Study – May 6, 2021

Figure 4-1: GEN-2010-014 & GEN-2011-022 Single Line Diagram (Modification Shunt Reactor)



5.0 Short Circuit Analysis

A short circuit study was performed using the 2021SP and 2028SP model for GEN-2010-014 and GEN-2011-022. The detailed results of the short circuit analysis are provided in Appendix B.

5.1 Methodology

The short circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 345 kV POI bus. The PSS/E “Automatic Sequence Fault Calculation (ASCC)” fault analysis module was used to calculate the fault current levels in the transmission system with and without GEN-2010-014 and GEN-2011-022 online.

5.2 Results

The results of the short circuit analysis for the 2021SP and 2028SP models are summarized in Table 5-1 through Table 5-3 respectively. The GEN-2010-014 and GEN-2011-022 POI bus (523097) fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 16.34 kA with the GEN-2010-014 and GEN-2011-022 project online.

The maximum fault current calculated within 5 buses of the GEN-2010-014 and GEN-2011-022 POI was less than 30 kA for the 2021SP and 2028SP models respectively. The maximum GEN-2010-014 and GEN-2011-022 contribution to three-phase fault current was about 17.1% and 2.39 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2021SP	13.94	16.23	2.29	16.4%
2028SP	13.95	16.34	2.39	17.1%

Table 5-2: 2021SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	8.4	0.00	-0.1%
115	29.7	0.60	4.3%
138	25.1	-0.03	-0.4%
230	26.7	1.04	7.4%
345	24.4	2.29	16.4%
Max	**29.7**	**2.29**	**16.4%**

Table 5-3: 2028SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	8.5	0.01	0.3%
115	24.8	0.69	5.0%
138	25.9	0.00	0.0%
230	25.5	1.12	7.9%
345	24.7	2.39	17.1%
Max	**25.9**	**2.39**	**17.1%**

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine configuration change and other modifications to the combined GEN-2010-014 and GEN-2011-022 project. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix C. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix A. The simulation plots can be found in Appendix D.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested GEN-2010-014 configuration of 126 x GE 2.82 MW (GEWTG0705) and GEN-2011-022 configuration of 108 x GE 2.82 MW (GEWTG0705). This stability analysis was performed using PTI's PSS/E version 33.10 software.

The stability models were developed using the DISIS-2017-001 models. The modifications requested for the GEN-2010-014 and GEN-2011-022 projects were used to create modified stability models for this impact study.

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

1. The LANOGSU10 generator (bus 523812) was GNET according to the DISIS-2017-001 report
2. The Goodwell generator voltage relays (buses 523170 & 523171) were disabled according to the DISIS-2017-001 report
3. G59REL at FRISCO_WND 3[1] (bus 523160) was disabled according to the DISIS-2017-001 report
4. Adjusted the GEN-2002-009 MVA base from 90 to 86.49
5. Adjusted the GEN-2002-009 Xsource from 0.3022 to 0.21157
6. The GEN-2017-018 frequency protection relay at bus 588637 was disabled

The modified dynamic model data for the GEN-2010-014 and GEN-2011-022 project is provided in Appendix A. The modified power flow models and associated dynamics database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2010-014 and GEN-2011-022 and other equally and prior queued projects in the cluster group[4]. In addition, voltages of five (5) buses away from the POI of GEN-2010-014 and GEN-2011-022 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 520 (AEPW), 524 (OKGE), 525 (WFEC), 526 (SPS), 531 (MIDW), 534 (SUNC), 536 (WERE) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

6.2 Fault Definitions

Aneden simulated the faults previously simulated for GEN-2010-014 and GEN-2011-022 and developed additional fault events as required. The new set of faults were simulated using the modified study

[4] Based on the DISIS-2017-001 Cluster Groups

models. The fault events included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults. The simulated faults are listed and described in below. These contingencies were applied to the modified 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and the 2028 Summer Peak models.

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT01-3PH	P1	3 phase fault on the BVRCNTY7 (515554) to BALKOW7 (515618) 345 kV line circuit 1, near BVRCNTY7. a. Apply fault at the BVRCNTY7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator BALKOWG1 (515658)** **Trip generator BALKOWG2 (515659)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT02-3PH	P1	3 phase fault on the BVRCNTY7 (515554) to BADGER (515677) 345 kV line circuit 1, near BVRCNTY7. a. Apply fault at the BVRCNTY7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT07-3PH	P1	3 phase fault on the TEXAS_CNTY 3 115 kV (523090) to HITCHLAND 3 (523093) 115 kV line circuit 1, near TEXAS_CNTY 3. a. Apply fault at the TEXAS_CNTY 3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT08-3PH	P1	3 phase fault on the HITCHLAND 3 115 kV (523093)/ 230 kV (523095) / 13.8 kV (523098) XFMR CKT 2, near HITCHLAND 3 115 kV. a. Apply fault at the HITCHLAND 3 115 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT09-3PH	P1	3 phase fault on the HITCHLAND 3 115 kV (523093) to HANSFORD 3 (523195) 115 kV line circuit 1, near HITCHLAND 3. a. Apply fault at the HITCHLAND 3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT10-3PH	P1	3 phase fault on the HITCHLAND 6 230 kV (523095) to MOORE_CNTY 6 (523309) 230 kV line circuit 1, near HITCHLAND 6. a. Apply fault at the HITCHLAND 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT11-3PH	P1	3 phase fault on the HITCHLAND 230 kV (523095) / 345 kV (523097)/ 13.2 kV (523094) transformer CKT 2, near HITCHLAND 230kV. a. Apply fault at the HITCHLAND 345 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT12-3PH	P1	3 phase fault on the HITCHLAND 7 (523097) to POTTER_CO 7 (523961) 345 kV line circuit 1, near HITCHLAND 7. a. Apply fault at the HITCHLAND 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT13-3PH	P1	3 phase fault on the HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT14-3PH	P1	3 phase fault on the HITCHLAND 7 (523097) to CARPENTER 7 (523823) 345 kV line circuit 1, near HITCHLAND 7. a. Apply fault at the HITCHLAND 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT19-3PH	P1	3 phase fault on the OCHILTREE 3 115 kV (523154) / 230 kV (523155) /13.8 kV (523151) XFMR CKT 1, near OCHILTREE 3 115 kV. a. Apply fault at the OCHILTREE 3 115 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT21-3PH	P1	3 phase fault on the MOORE_E 3 115 kV (523308)/ 230 kV (523309) / 13.8 kV (523302) XFMR CKT 1, near MOORE_E 3 115 kV. a. Apply fault at the MOORE_E 3 115 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT22-3PH	P1	3 phase fault on the MOORE_CNTY 6 (523309) to POTTER_CO 6 (523959) 230 kV line circuit 1, near MOORE_CNTY 6. a. Apply fault at the MOORE_CNTY 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT23-3PH	P1	3 phase fault on the HARBNGR3 345 kV (531512) /115 kV (531510) /13.8 kV (531511) XFMR CKT 1, near HARBNGR7 345kV. a. Apply fault at the HARBNGR3 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT24-3PH	P1	3 phase fault on the POTTER_CO 345 kV (523961) /230 kV (523959) /13.8 kV (523957) XFMR CKT 1, near POTTER_CO 345kV. a. Apply fault at the POTTER_CO 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT26-3PH	P1	3 phase fault on the BUSHLAND 230 kV (524267) /115 kV (524266) /13.2 kV (524263) XFMR CKT 1, near BUSHLAND 230 kV. a. Apply fault at the BUSHLAND 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT27-3PH	P1	3 phase fault on the POTTER_CO 6 (523959) to BUSHLAND 6 (524267) 230 kV line circuit 1, near POTTER_CO 6. a. Apply fault at the POTTER_CO 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT39-3PH	P1	3 phase fault on the BUSHLAND 6 (524267) to DEAFSMITH 6 (524623) 230 kV line circuit 1, near BUSHLAND 6. a. Apply fault at the BUSHLAND 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT51-3PH	P1	3 phase fault on the POTTER_CO 230 kV (523959) /345 kV (523961)/ 13.2 kV (523957) XFMR CKT 1, near POTTER_CO 230 kV. a. Apply fault at the POTTER_CO 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT57-3PH	P1	3 phase fault on the POTTER_CO 7 (523961) to HITCHLAND 7 (523097) 345 kV line circuit 1, near POTTER_CO 7. a. Apply fault at the POTTER_CO 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT58-3PH	P1	3 phase fault on the CHAN+TASCOS6 (523869) to XIT_INTG (523221) 230 kV line circuit 1, near CHAN+TASCOS6. a. Apply fault at the CHAN+TASCOS6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT59-3PH	P1	3 phase fault on the POTTER_CO 6 (523959) to MOORE_CNTY 6 (523309) 230 kV line circuit 1, near POTTER_CO 6. a. Apply fault at the POTTER_CO 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT61-3PH	P1	3 phase fault on the BADGER 7 (515677) to G16-003-TAP (560071) 345 kV line circuit 1, near BADGER 7. a. Apply fault at the BADGER 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT62-3PH	P1	3 phase fault on the G16-003-TAP (560071) to BADGER 7 (515677) 345 kV line circuit 1, near G16-003-TAP. a. Apply fault at the G16-003-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT63-3PH	P1	3 phase fault on the CARPENTER 7 (523823) to FINNEY 7 (523853) 345 kV line circuit 1, near CARPENTER 7. a. Apply fault at the CARPENTER 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT14-PO1	P6	**PRIOR OUTAGE of HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1** 3 phase fault on the HITCHLAND 7 (523097) to CARPENTER 7 (523823) 345 kV line circuit 1, near HITCHLAND 7. a. Apply fault at the HITCHLAND 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT13-PO2	P6	**PRIOR OUTAGE of HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 2** 3 phase fault on the HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT19-PO3	P6	**PRIOR OUTAGE of HITCHLAND 3 115 kV (523093) to HANSFORD 3 (523195) 115 kV line circuit 1** 3 phase fault on the OCHILTREE 3 115 kV (523154) / 230 kV (523155) /13.8 kV (523151) XFMR CKT 1, near OCHILTREE 3 115 kV. a. Apply fault at the OCHILTREE 3 115 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT12-PO5	P6	**PRIOR OUTAGE of HITCHLAND 6 230 kV (523095) to MOORE_CNTY 6 (523309) 230 kV line circuit 1** 3 phase fault on the HITCHLAND 7 (523097) to POTTER_CO 7 (523961) 345 kV line circuit 1, near HITCHLAND 7. a. Apply fault at the HITCHLAND 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9001-3PH	P1	3 phase fault on the HITCHLAND 7 (523097) to Novus (523112) 345 kV line circuit 1, near HITCHLAND 7. a. Apply fault at the HITCHLAND 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generators NOVUS_WND 1 (523107)** **Trip generators G06-044GEN1A (579373)** **Trip generators G06-044GEN2A (579376)** **Trip generators G06-044GEN2B (579380)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on the HITCHLAND 7 (523097) to G10014G11022 (576397) 345 kV line circuit 1, near HITCHLAND 7. a. Apply fault at the HITCHLAND 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G10-014-GEN1 (576400)** **Trip generator G10-014-GEN2 (576410)** **Trip generator G11-022-GEN1 (599148)** **Trip generator G11-022-GEN2 (599150)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9003-3PH	P1	3 phase fault on the HITCHLAND 7 345 kV (523097) / NOBLE_WND 3 115 kV (523103)/ NOBLE_TR 1 13.2 kV (523102) XFMR CKT 1, near HITCHLAND 7 345 kV. a. Apply fault at the HITCHLAND 7 345 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer. **Trip generator NBLWND-WTG11 (523121)** **Trip generator NBLWND-WTG21 (523122)** **Trip generator NBLWND-WTG31 (523123)**
FLT9004-3PH	P1	3 phase fault on the HITCHLAND 345 kV (523097) /230 kV (523095) /13.2 kV (523091) transformer CKT 1, near HITCHLAND 345kV. a. Apply fault at the HITCHLAND 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9005-3PH	P1	3 phase fault on the CLARKCOUNTY7 (539800) to GEN-2011-008 (582008) 345 kV line circuit 1, near CLARKCOUNTY7. a. Apply fault at the CLARKCOUNTY7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G11-008-GEN1 (582208)** **Trip generator G11-008-GEN2 (582598)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9006-3PH	P1	3 phase fault on the CARPENTER 7 (523823) to HARBNG7 (531512) 345 kV line circuit Z1, near CARPENTER 7. a. Apply fault at the CARPENTER 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9007-3PH	P1	3 phase fault on the FINNEY 7 (523853) to HOLCOMB7 (531449) 345 kV line circuit 1, near FINNEY 7. a. Apply fault at the FINNEY 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 phase fault on the FINNEY 7 (523853) to BUFF_DUNES7 (523118) 345 kV line circuit 1, near FINNEY 7. a. Apply fault at the FINNEY 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G08-018-GEN1 (579403)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	P1	3 phase fault on the FINNEY 7 (523853) to G17-032-TAP (588754) 345 kV line circuit 1, near FINNEY 7. a. Apply fault at the FINNEY 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G17-032-GEN1 (588753)** **Trip generator LAMAR 6 (599951)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9010-3PH	P1	3 phase fault on the HITCHLAND 3 230 kV (523095) /115 kV (523093)/ 13.2 kV (523092) XFMR CKT 1, near HITCHLAND 3 230 kV. a. Apply fault at the HITCHLAND 3 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9011-3PH	P1	3 phase fault on the HITCHLAND 6 230 kV (523095) to OCHILTREE (523155) 230 kV line circuit 1, near HITCHLAND 6. a. Apply fault at the HITCHLAND 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9012-3PH	P1	3 phase fault on the POTTER_CO 7 (523961) to SPNSPUR_WND7 (524296) 345 kV line circuit 1, near POTTER_CO 7. a. Apply fault at the POTTER_CO 6 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G08-051-GEN2 (579413)** **Trip generator SPNSPUR_WND1 (599106)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9013-3PH	P1	3 phase fault on the BVRCNTY7 (515554) to PALDR2W7 (515590) 345 kV line circuit 1, near BVRCNTY7. a. Apply fault at the BVRCNTY7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G08-047-GEN2 (573510)** **Trip generator G08-047-GEN1 (515905)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9014-3PH	P1	3 phase fault on the BVRCNTY7 (515554) to CLARKCOUNTY7 (539800) 345 kV line circuit 1, near BVRCNTY7. a. Apply fault at the BVRCNTY7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9015-3PH	P1	3 phase fault on the BVRCNTY7 (515554) to GRAPEVINE (560035) 345 kV line circuit 1, near BVRCNTY7. a. Apply fault at the BVRCNTY7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9016-3PH	P1	3 phase fault on the GRAPEVINE (560035) to POTTER_CO 7 (523961) 345 kV line circuit 1, near GRAPEVINE. a. Apply fault at the GRAPEVINE 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9017-3PH	P1	3 phase fault on the GRAPEVINE (560035) to CHISHOLM7 (511553) 345 kV line circuit 1, near GRAPEVINE. a. Apply fault at the GRAPEVINE 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9018-3PH	P1	3 phase fault on the BADGER 7 (515677) to GEN-2011-014 (515686) 345 kV line circuit 1, near BADGER 7. a. Apply fault at the BADGER 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G11-014-GEN1 (515678) and G11-014-GEN2 (515682)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9019-3PH	P1	3 phase fault on the BADGER 7 (515677) to GEN-2015-082 (585190) 345 kV line circuit 1, near BADGER 7. a. Apply fault at the BADGER 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G15-082-GEN1 (585193)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9020-3PH	P1	3 phase fault on the CLARKCOUNTY7 (539800) to SPERVIL7 (531469) 345 kV line circuit 1, near CLARKCOUNTY7. a. Apply fault at the CLARKCOUNTY7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9021-3PH	P1	3 phase fault on the CLARKCOUNTY7 (539800) to THISTLE7 (539801) 345 kV line circuit 1, near CLARKCOUNTY7. a. Apply fault at the CLARKCOUNTY7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9022-3PH	P1	3 phase fault on the THISTLE7 (539801) to BUFFALO7 (532782) 345 kV line circuit 1, near THISTLE7. a. Apply fault at the THISTLE7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9023-3PH	P1	3 phase fault on the THISTLE7 (539801) to GEN-2017-018 (588630) 345 kV line circuit 1, near THISTLE7. a. Apply fault at the THISTLE7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G17-018-GEN1 (588633)** **Trip generator G17-018-GEN2 (588637)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9024-3PH	P1	3 phase fault on the THISTLE7 345 kV (539801) /138 kV (539804) /13.8 kV (539802) transformer CKT 1, near THISTLE7 345kV. a. Apply fault at the HITCHLAND 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9025-3PH	P1	3 phase fault on the THISTLE7 (539801) to DGRASSE7 (515852) 345 kV line circuit 1, near THISTLE7. a. Apply fault at the THISTLE7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9026-3PH	P1	3 phase fault on the CLARKCOUNTY7 (539800) to GEN-2012-024 (583370) 345 kV line circuit 1, near CLARKCOUNTY7. a. Apply fault at the CLARKCOUNTY7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G12-024-GEN1 (583373)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9027-3PH	P1	3 phase fault on the CLARKCOUNTY7 (539800) to P1 MPT PRI (539852) 345 kV line circuit 1, near CLARKCOUNTY7. a. Apply fault at the CLARKCOUNTY7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G11-008-GEN3 (582978)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9028-3PH	P1	3 phase fault on the CLARKCOUNTY7 (539800) to G16-046-TAP (560080) 345 kV line circuit 1, near CLARKCOUNTY7. a. Apply fault at the CLARKCOUNTY7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9029-3PH	P1	3 phase fault on the HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 2, near HITCHLAND. a. Apply fault at the HITCHLAND 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT1001-SB	P4	**Stuck Breaker on at POTTER_CO 7 (523961) at 345kV bus** a. Apply single-phase fault at POTTER_CO 7 (523961) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the Bus POTTER_CO 7 (523961). **Trip generator BALKOWG1 (579413)** **Trip generator BALKOWG2 (599106)**
FLT1002-SB	P4	**Stuck Breaker on at CARPENTER 7 (523823) at 345kV bus** a. Apply single-phase fault at CARPENTER 7 (523823) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the Bus CARPENTER 7 (523823).
FLT1003-SB	P4	**Stuck Breaker on at BVRCNTY7 (515554) at 345kV bus** a. Apply single-phase fault at BVRCNTY7 (515554) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the BVRCNTY7 (515554) to BADGER (515677) 345 kV line CKT 2. d.Trip the BVRCNTY7 (515554) to BALKOW (515618) 345 kV line CKT 1. Trip generator BALKOWG1 (515658) Trip generator BALKOWG2 (515659)

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1004-SB	P4	**Stuck Breaker on at BVRCNTY7 (515554) at 345kV bus** a. Apply single-phase fault at BVRCNTY7 (515554) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the BVRCNTY7 (515554) to PALDR2W7 (515590) 345 kV line CKT 1. d. Trip the BVRCNTY7 (515554) to HITCHLAND 7 (523097) 345 kV line CKT 1. Trip generator G08-047-GEN1 (515905) Trip generator G08-047-GEN2 (573510)
FLT1005-SB	P4	**Stuck Breaker on at BVRCNTY7 (515554) at 345kV bus** a. Apply single-phase fault at BVRCNTY7 (515554) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the BVRCNTY7 (515554) to HITCHLAND 7 (523097) 345 kV line CKT 1. d. Trip the BVRCNTY7 (515554) to HITCHLAND 7 (523097) 345 kV line CKT 2.
FLT1006-SB	P4	**Stuck Breaker on at BVRCNTY7 (515554) at 345kV bus** a. Apply single-phase fault at BVRCNTY7 (515554) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the BVRCNTY7 (515554) to BADGER (515677) 345 kV line CKT 2. d. Trip the BVRCNTY7 (515554) to BADGER (515677) 345 kV line CKT 1.
FLT1007-SB	P4	**Stuck Breaker on at BVRCNTY7 (515554) at 345kV bus** a. Apply single-phase fault at BVRCNTY7 (515554) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the BVRCNTY7 (515554) to HITCHLAND 7 (523097) 345 kV line CKT 2. d. Trip the BVRCNTY7 (515554) to BALKOW (515618) 345 kV line CKT 1. **Trip generator BALKOWG1 (515658)** **Trip generator BALKOWG2 (515659)**
FLT1008-SB	P4	**Stuck Breaker on at BVRCNTY7 (515554) at 345kV bus** a. Apply single-phase fault at BVRCNTY7 (515554) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the BVRCNTY7 (515554) to PALDR2W7 (515590) 345 kV line CKT 1. d. Trip the BVRCNTY7 (515554) to BADGER (515677) 345 kV line CKT 1. **Trip generator G08-047-GEN1 (515905)** **Trip generator G08-047-GEN2 (573510)**
FLT1009-SB	P4	**Stuck Breaker on at FINNEY (523853) at 345kV bus** a. Apply single-phase fault at FINNEY (523853) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the FINNEY (523853) to BUFF_DUNES 7 (523118) 345kV line CKT 1. d. Trip the FINNEY (523853) to G17-032-TAP (588754) 345kV line CKT 1. **Trip Generator G08-018-GEN1 (579403).** **Trip Generator LAMAR (599951).** **Trip Generator G17-032-GEN1 (588753).**
FLT1010-SB	P4	**Stuck Breaker on at FINNEY (523853) at 345kV bus** a. Apply single-phase fault at FINNEY (523853) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the FINNEY (523853) to HOLCOMB7 (531449) 345kV line CKT 1. d. Trip the FINNEY (523853) to G17-032-TAP (588754) 345kV line CKT 1. **Trip Generator LAMAR (599951).** **Trip Generator G17-032-GEN1 (588753).**
FLT1012-SB	P4	**Stuck Breaker on at FINNEY (523853) at 345kV bus** a. Apply single-phase fault at FINNEY (523853) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the FINNEY (523853) to HOLOCOMB (531449) 345kV line CKT 1. d. Trip the FINNEY (523853) to CARPENTER 7 (523823) 345kV line CKT 1.
FLT1014-SB	P4	**Stuck Breaker on at FINNEY (523853) at 345kV bus** a. Apply single-phase fault at FINNEY (523853) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the FINNEY (523853) to BUFF_DUNES 7 (523118) 345kV line CKT 1. d. Trip the FINNEY (523853) to CARPENTER 7 (523823) 345kV line CKT 1. **Trip Generator G08-018-GEN1 (579403).**
FLT1015-SB	P4	**Stuck Breaker on at HITCHLAND 6 (523095) at 230kV bus** a. Apply single-phase fault at HITCHLAND 6 (523095) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 230kV (523095) to HITCHLAND 115kV (523093) HITCHLAND 13.2kV (523092) XFMR CKT 1. d. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1016-SB	P4	**Stuck Breaker on at HITCHLAND 6 (523095) at 230kV bus** a. Apply single-phase fault at HITCHLAND 6 (523095) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 230kV (523095) to HITCHLAND 115kV (523093) HITCHLAND 13.2kV (523098) XFMR CKT 2. d. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2.
FLT1017-SB	P4	**Stuck Breaker on at HITCHLAND 6 (523095) at 230kV bus** a. Apply single-phase fault at HITCHLAND 6 (523095) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 230kV (523095) to HITCHLAND 115kV (523093) HITCHLAND 13.2kV (523092) XFMR CKT 1. d. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1. e. Trip the HITCHLAND (523095) to Moore County 230kV (523309) line CKT 1.
FLT1018-SB	P4	**Stuck Breaker on at HITCHLAND 6 (523095) at 230kV bus** a. Apply single-phase fault at HITCHLAND 6 (523095) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 230kV (523095) to HITCHLAND 115kV (523093) HITCHLAND 13.2kV (523098) XFMR CKT 2. d. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2. e. Trip the HITCHLAND (523095) to Moore County 230kV (523309) line CKT 1.
FLT1019-SB	P4	**Stuck Breaker on at HITCHLAND 6 (523095) at 230kV bus** a. Apply single-phase fault at HITCHLAND 6 (523095) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 230kV (523095) to HITCHLAND 115kV (523093) HITCHLAND 13.2kV (523098) XFMR CKT 2. d. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2. e. Trip the HITCHLAND (523095) to OCHILTREE 6 230kV (523155) line CKT 1.
FLT1020-SB	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND (523097) to POTTER_CO 7 345kV (523961) line CKT 1. d. Trip the HITCHLAND 345kV (523097) to NOBLE_WND 3 115kV (523103) to NOBLE_TR 1 13.8kV (523102) XFMR CKT 1. **Trip Generators GRPLINS-WT2 (523123), HSFD-GEN1 (523122), GRPLAINS-WT4 (523121).**
FLT1021-SB	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1. d. Trip the HITCHLAND (523097) to NOVUS (523112) 345kV line CKT 1. **Trip Generators G06-044**
FLT1022-SB	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND (523097) to BVRCNTY7 (515554) 345kV line CKT 1. d. Trip the HITCHLAND (523097) to NOVUS (523112) 345kV line CKT 1. **Trip Generators G06-044**
FLT1023-SB	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) to HITCHLAND 13.2kV (523094) XFMR CKT 2. d. Trip the HITCHLAND (523097) to BVRCNTY7 (515554) 345kV line CKT 1. e. Trip the Capbank.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1024-SB	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2. d. Trip the HITCHLAND (523097) to BVRCNTY7 (515554) 345kV line CKT 2. e. Trip the Capbank.
FLT1025-SB	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2. d. Trip the HITCHLAND 345kV (523097) to NOBLE_WND 3 115kV (523103) to NOBLE_TR 1 13.8kV (523102) XFMR CKT 1. **Trip Generators GRPLINS-WT2 (523123), HSFD-GEN1 (523122), GRPLAINS-WT4 (523121).** e. Trip the Capbank.
FLT1026-SB	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND (523097) to POTTER_CO 7 345kV (523961) line CKT 1. d. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) to HITCHLAND 13.2kV (523091) XFMR CKT 1.
FLT1027-SB	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1. d. Trip the HITCHLAND (523097) to G10014G11022 (576397) 345kV line CKT 1. **Trip Generators G10-014-GEN1 (576400), G10-014-GEN2 (576410), G11-022-GEN1 (599148), G11-022-GEN2 (599150).**
FLT1028-SB	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) to HITCHLAND 13.2kV (523091) XFMR CKT 1. d. Trip the HITCHLAND 345kV (523097) to CARPENTER 7 (523823) 345kV line CKT 1.
FLT1029-SB	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND (523097) to BVRCNTY7 (515554) 345kV line CKT 2. d. Trip the HITCHLAND (523097) to G10014G11022 (576397) 345kV line CKT 1. **Trip Generators G10-014-GEN1 (576400), G10-014-GEN2 (576410), G11-022-GEN1 (599148), G11-022-GEN2 (599150).**
FLT1030-SB	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2. d. Trip the HITCHLAND 345kV (523097) to CARPENTER 7 (523823) 345kV line CKT 1. e. Trip the Capbank.
FLT1031-SB	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2. d. Trip the HITCHLAND (523097) to G10014G11022 (576397) 345kV line CKT 1. **Trip Generators G10-014-GEN1 (576400), G10-014-GEN2 (576410), G11-022-GEN1 (599148), G11-022-GEN2 (599150).** e. Trip the Capbank.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT12-PO1	P6	**PRIOR OUTAGE of HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1** 3 phase fault on the HITCHLAND (523097) to Potter_CO 7 345kV (523961) line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9004-PO1	P6	**PRIOR OUTAGE of HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1** 3 phase fault on the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1, near HITCHLAND 345kV. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9029-PO1	P6	**PRIOR OUTAGE of HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1** 3 phase fault on the HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 2, near HITCHLAND. a. Apply fault at the HITCHLAND 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT12-PO2	P6	**PRIOR OUTAGE of HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 2** 3 phase fault on the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT14-PO2	P6	**PRIOR OUTAGE of HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 2** 3 phase fault on the HITCHLAND 7 (523097) to CARPENTER 7 (523823) 345 kV line circuit 1, near HITCHLAND 7. a. Apply fault at the HITCHLAND 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9004-PO2	P6	**PRIOR OUTAGE of HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 2** 3 phase fault on the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1, near HITCHLAND 345kV. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT12-PO4	P6	**PRIOR OUTAGE of the HITCHLAND (523097) to CARPENTER 7 (523823) 345kV line CKT 1;** 3 phase fault on the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT13-PO4	P6	**PRIOR OUTAGE of the HITCHLAND (523097) to CARPENTER 7 (523823) 345kV line CKT 1;** 3 phase fault on the HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9004-PO4	P6	**PRIOR OUTAGE of the HITCHLAND (523097) to CARPENTER 7 (523823) 345kV line CKT 1;** 3 phase fault on the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1, near HITCHLAND 345kV. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT12-PO6	P6	**PRIOR OUTAGE of the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2;** 3 phase fault on the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT13-PO6	P6	**PRIOR OUTAGE of the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2;** 3 phase fault on the HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT14-PO6	P6	**PRIOR OUTAGE of the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2;** 3 phase fault on the HITCHLAND (523097) to CARPENTER 7 345kV (523823) CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9004-PO6	P6	**PRIOR OUTAGE of the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2;** 3 phase fault on the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1, near HITCHLAND 345kV. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT13-PO7	P6	**PRIOR OUTAGE of the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1;** 3 phase fault on the HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT14-PO7	P6	**PRIOR OUTAGE of the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1;** 3 phase fault on the HITCHLAND (523097) to CARPENTER 7 345kV (523823) CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9004-PO7	P6	**PRIOR OUTAGE of the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1;** 3 phase fault on the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1, near HITCHLAND 345kV. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

6.3 Results

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

Table 6-2: GEN-2010-014 & GEN-2011-022 Dynamic Stability Results

Fault ID	19WP			21LL			21SP			28SP		
	Volt Violation	Volt Recovery	Stable	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	Pass	Pass	Stable
FLT02-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT08-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT09-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT10-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT11-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT12-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT13-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT14-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT19-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT21-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT22-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT23-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT24-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT26-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT27-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT39-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT51-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT57-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT58-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT59-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT61-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT62-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT63-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 Continued

Fault ID	19WP			21LL			21SP			28SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9029-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 Continued

Fault ID	19WP			21LL			21SP			28SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable*	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1012-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1014-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1015-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1016-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1017-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1018-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1019-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1020-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1021-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1022-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1023-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1024-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1025-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1026-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1027-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1028-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1029-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1030-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1031-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT12-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9029-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT14-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 Continued

Fault ID	19WP			21LL			21SP			28SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT13-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT12-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT14-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT19-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT12-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT13-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT12-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT12-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT13-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT14-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT13-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT14-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

*** G17-032 reactive power drifting was observed in both the DISIS-2017-001 case and MRIS case so it is a base case issue**

During numerous faults the MAJSTC Units (523941 & 523942) showed oscillations. This issue was reported as a base case issue in the DISIS-2017-001 stability report. As this was observed in both the DISIS and modification cases, it was not attributed to the GEN-2010-014 and GEN-2011-022 project.

During numerous faults the OECGT Units (511939, 511940, 511942, & 511943) showed abnormal fluctuations in the post-contingency period. This issue was reported as a base case issue in the DISIS-2017-001 stability report. As this was observed in both the DISIS and modification cases, it was not attributed to the GEN-2010-014 and GEN-2011-022 project.

After the loss of the Beaver County to Hitchland double circuit the GEN-2017-032 Unit (588753) showed reactive power drifting. This was observed in both the DISIS and modification cases, and was not attributed to the GEN-2010-014 and GEN-2011-022 project. Figure 6-1 shows the reactive power drifting during FLT1005-SB in the 19WP Modification case. This problem was also present in the existing DISIS-2017-001 19WP case as shown in Figure 6-2.

Figure 6-1: FLT1005-SB GEN-2017-032 Reactive Power Drifting (19WP Modification Case)

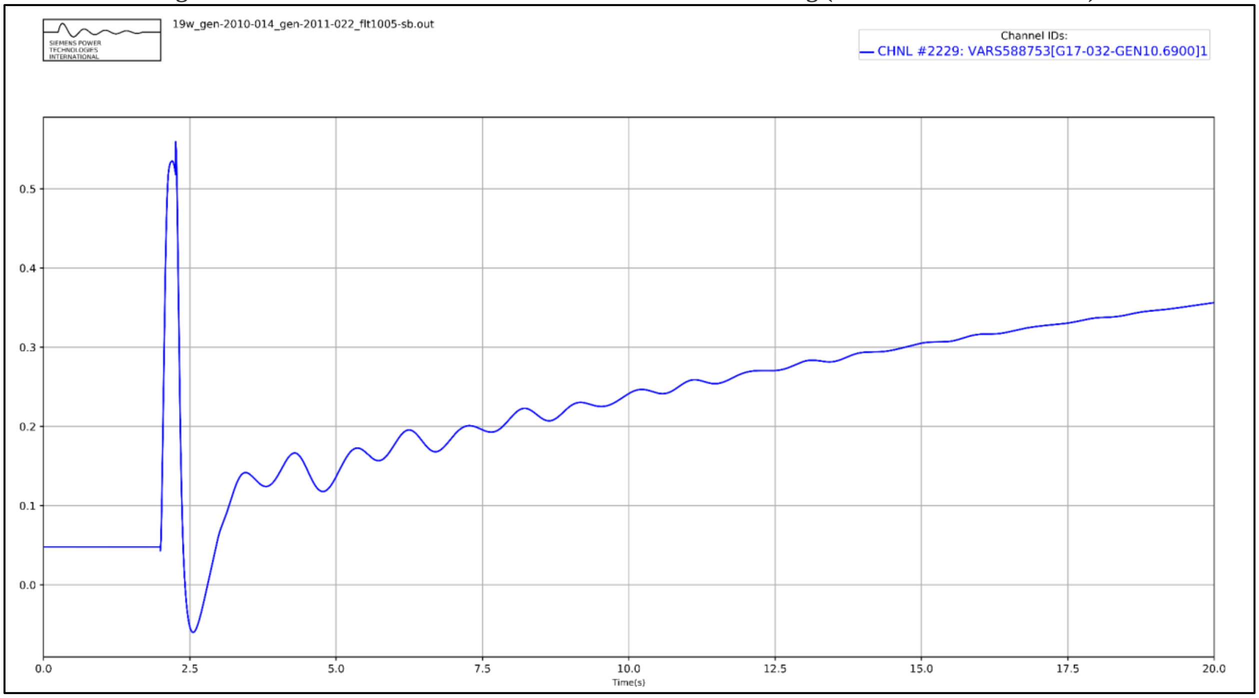
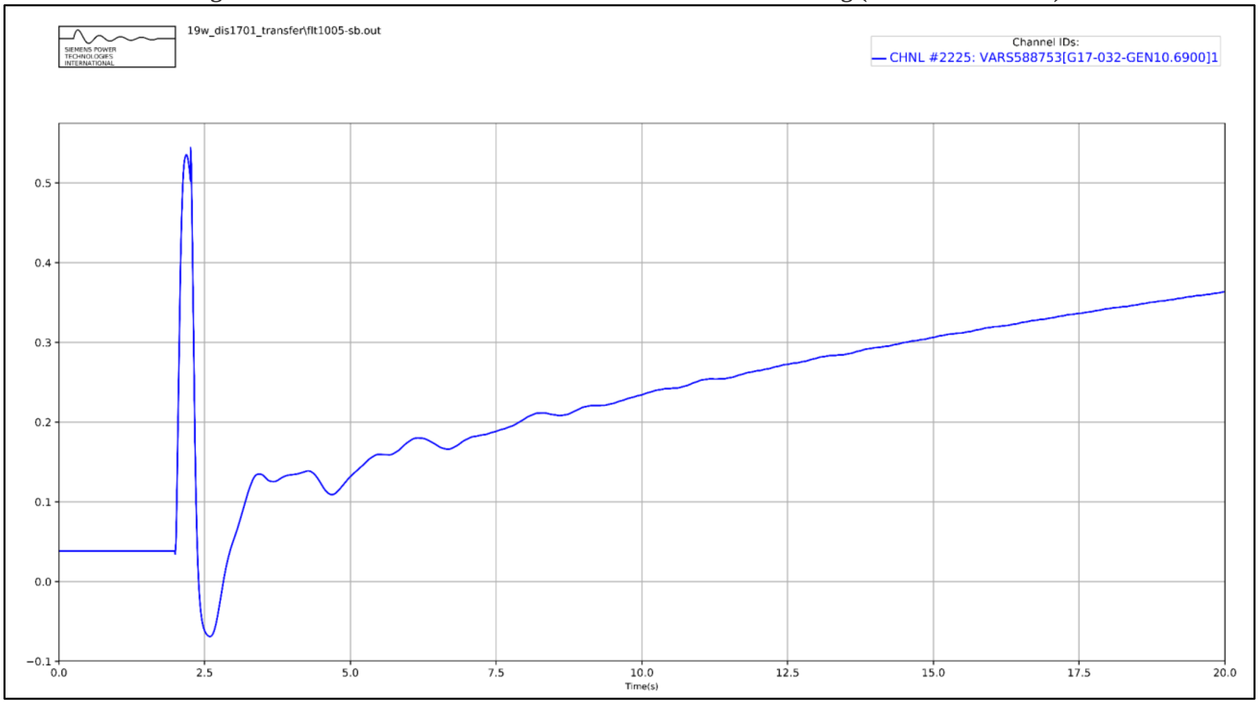


Figure 6-2: FLT1005-SB GEN-2017-032 Reactive Power Drifting (19WP DISIS Case)



There were no damping or voltage recovery violations attributed to the GEN-2010-014 and GEN-2011-022 project observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

7.0 Modified Capacity Exceeds GIA Capacity

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

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

7.1 Results

The modified combined generating capacity of GEN-2010-014 and GEN-2011-022 (659.88 MW) exceeds the GIA Interconnection Service amount, 657.8 MW, as listed in Appendix A of the GIA.

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

8.0 Material Modification Determination

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

8.1 Results

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

This determination implies that any network upgrades already required by GEN-2010-014 and GEN-2011-022 would not be negatively impacted and that no new upgrades are required due to the requested modification, thus not resulting in a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.

9.0 Conclusions

The Interconnection Customer for GEN-2010-014 and GEN-2011-022 requested a Modification Request Impact Study to assess the impact of the turbine and facility change to 126 x GE 2.82 MW (355.32 MW) and 108 x GE 2.82 MW (304.56 MW) respectively for a total capacity of 659.88 MW. This combined generating capacity for GEN-2010-014 and GEN-2011-022 (659.88 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, 657.8 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line, reactive power devices, and main substation transformers.

SPP determined that power flow should not be performed based on the POI MW injection decrease of 1.8% compared to the DISIS-2017-001 power flow models. However, SPP determined that the turbine change from Siemens to GE required short circuit and dynamic stability analyses.

All analyses were performed using the PTI PSS/E version 33 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak models showed that the GEN-2010-014 and GEN-2011-022 project needed 59.1 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 24.9 MVAr found for the existing GEN-2010-014 and GEN-2011-022 configuration found in the previous modification study[5]. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The results from the short circuit analysis with the updated configuration showed that the maximum GEN-2010-014 and GEN-2011-022 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2010-014 and GEN-2011-022 POI was no greater than 2.39 kA for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2010-014 and GEN-2011-022 generators online were below 30 kA for the 2021SP and 2028SP models.

The dynamic stability analysis was performed using PTI PSS/E version 33.10 software for the four modified study models, 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak. Up to 103 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

The results of the dynamic stability analysis showed that during numerous faults the MAJSTC Units (523941 & 523942) showed oscillations, and the OECGT Units (511939, 511940, 511942, & 511943) showed abnormal fluctuations in the post-contingency period. These issues were reported as base case

[5] GEN-2010-014 and GEN-2011-022 Modification Request Impact Study – May 6, 2021

issues in the DISIS-2017-001 stability report. As this was observed in both the DISIS and modification cases, it was not attributed to the GEN-2010-014 and GEN-2011-022 project.

After the loss of the Beaver County to Hitchland double circuit the GEN-2017-032 Unit (588753) showed reactive power drifting. This was observed in both the DISIS and modification cases, and was not attributed to the GEN-2010-014 and GEN-2011-022 project.

There were no damping or voltage recovery violations attributed to the GEN-2010-014 and GEN-2011-022 project observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

The requested modification has been determined by SPP to not be a Material Modification. The requested modification does not have a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date. As the requested modification places the generating capacity of the Interconnection Request at a higher amount than its Interconnection Service, the customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

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

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

Nothing in this study should be construed as a guarantee of transmission service or delivery rights. If the customer wishes to obtain deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the customer.