Report on

GEN-2016-149, GEN-2016-150, & GEN-2016-174 Modification Request Impact Study

Revision R1 **August 3, 2023**

Submitted to
Southwest Power Pool

Southwest Power Pool

anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
8/3/2023	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-2016-149, GEN-2016-150, and GEN-2016-174, active Generation Interconnection Requests (GIR) with a common Point of Interconnection (POI) at the Stranger Creek 345 kV Substation.

The GEN-2016-149, GEN-2016-150, and GEN-2016-174 wind projects interconnect in the Evergy Kansas Central (WERE) control area. There are four projects connected in series to the POI: GEN-2016-149, GEN-2016-174, GEN-2016-176 and GEN-2016-150 in that order.

GEN-2016-149 & GEN-2016-150 share a Generator Interconnection Agreement (GIA) and have a combined capacity of 604 MW, and GEN-2016-174 has a capacity of 302 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of the GEN-2016-149 turbine configuration to 12 x GE 2.32 MW + 4 x GE 2.52 MW + 139 x GE 2.82 MW (5 turbines reduced to 2.725 MW) for a total capacity of 429.9 MW and an assumed dispatch of 429.425 MW. The GEN-2016-150 turbine configuration has also been modified to 12 x GE 2.32 MW + 66 x GE 2.82 MW for a total capacity and assumed dispatch of 213.96 MW. This generating capability for GEN-2016-149 & GEN-2016-150 (643.86 MW) exceeds its GIA Interconnection Service amount, 604 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. GEN-2016-174 did not have any changes to the turbine configuration.

In addition, the GEN-2016-149 & GEN-2016-150 modification request included changes to the generation interconnection line configuration, collection systems, generator step-up transformers, main substation transformers, and reactive power devices. The GEN-2016-149 project was also relocated to be positioned just before GEN-2016-150 at the end of the gen-tie line. The GEN-2016-174 included the addition of a series capacitor to the generation interconnection line as well as a shunt reactor and capacitors at the main substation. The existing and modified configurations for GEN-2016-149, GEN-2016-150, and GEN-2016-174 are shown in Table ES-2, Table ES-3, and Table ES-4 respectively.

Table ES-1: GEN-2016-149, GEN-2016-150, & GEN-2016-174 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2016-149	Stranger Creek 345 kV (532772)	151 x GE 2.0 MW = 302 MW	302
GEN-2016-150	Stranger Creek 345 kV (532772)	151 x GE 2.0 MW = 302 MW	302
GEN-2016-174	Stranger Creek 345 kV (532772)	59 x GE 2.3 MW + 3 x GE 2.52 MW + 58 x GE 2.72 MW= 301.02 MW	302

Table ES-2: GEN-2016-149 Modification Request

<table>
<tr><th>Facility</th><th>Existing Configuration</th><th colspan="5">Modification Configuration</th></tr>
<tr><td>Point of Interconnection</td><td>Stranger Creek 345 kV (532772)</td><td colspan="5">Stranger Creek 345 kV (532772)</td></tr>
<tr><td>Configuration/Capacity</td><td>151 x GE 2.0 MW = 302 MW</td><td colspan="5">12 x GE 2.32 MW + 4 x GE 2.52 MW + 139 x GE 2.82 MW (5 turbines reduced to 2.725 MW) = 429.9 MW [429.425 MW Dispatched]
PPC in place to limit GEN-2016-149 & GEN-2016-150 combined POI injection to 604 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td>Stranger Creek to GEN-2016-149 345 kV:
Length = 38 miles
R = 0.001208 pu
X = 0.017664 pu
B = 0.348080 pu
Rating MVA = 1084 MVA</td><td colspan="5">GEN-2016-176 to GEN-2016-149 345 kV:
Length = 64.6 miles
R = 0.002054 pu
X = 0.030030 pu
B = 0.595130 pu
Rating MVA = 1293 MVA</td></tr>
<tr><td>Main Substation Transformer[1]</td><td>X = 8.997%,
R = 0.225%,
Winding MVA = 204 MVA,
Rating MVA = 340 MVA</td><td colspan="2">X = 8.497%, R = 0.212%,
Winding MVA = 135 MVA,
Rating MVA = 242 MVA</td><td colspan="3">X =8.497%, R = 0.212%,
Winding MVA = 135 MVA,
Rating MVA = 242 MVA</td></tr>
<tr><td>Equivalent GSU Transformer[1]</td><td>Gen 1 Equivalent Qty: 151
X = 5.67%,
R = 0.76%,
Winding MVA = 347.3 MVA,
Rating MVA = 347.3 MVA</td><td>Gen 1 Equivalent Qty: 6
X = 5.724%,
R = 0.537%,
Winding MVA = 15 MVA,
Rating MVA = 17.4 MVA</td><td>Gen 2 Equivalent Qty: 71
X = 5.724%,
R = 0.537%,
Winding MVA = 198.8 MVA,
Rating MVA = 230.8 MVA</td><td>Gen 3 Equivalent Qty: 4
X = 5.724%,
R = 0.537%,
Winding MVA = 10 MVA,
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X = 5.724%,
R = 0.537%,
Winding MVA = 15 MVA,
Rating MVA = 17.4 MVA</td><td>Gen 5 Equivalent Qty: 68
X = 5.724%,
R = 0.537%,
Winding MVA = 190.4 MVA,
Rating MVA = 221 MVA</td></tr>
<tr><td>Equivalent Collector Line[2]</td><td>R = 0.001841 pu
X = 0.001682 pu
B = 0.046781 pu</td><td colspan="2">R = 0.005407 pu
X = 0.011029 pu
B = 0.142779 pu</td><td colspan="3">R = 0.006337 pu
X = 0.012430 pu
B = 0.146922 pu</td></tr>
<tr><td>Generator Dynamic Model[3]
& Power Factor</td><td>151 x GE 2.0 MW (GEWTGCU1)[3]
Leading: 0.95
Lagging: 0.95</td><td>6 x GE 2.32 MW (GEWTG0705)[3]
Leading: 0.9
Lagging: 0.9</td><td>71 x GE 2.82 MW (GEWTG0705)[3]
Leading: 0.9
Lagging: 0.9</td><td>4 x GE 2.52 MW (GEWTG0705)[3]
Leading: 0.9
Lagging: 0.9</td><td>6 x GE 2.32 MW (GEWTG0705)[3]
Leading: 0.9
Lagging: 0.9</td><td>68 x GE 2.82 MW (GEWTG0705)[3]
Leading: 0.9
Lagging: 0.9</td></tr>
<tr><td>Reactive Power Devices</td><td>N/A</td><td colspan="5">2 x 24 MVAR 34.5 kV Capacitor Bank
1 x 100 MVAR 345 kV Reactor</td></tr>
</table>

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

Table ES-3: GEN-2016-150 Modification Request

Facility	Existing Configuration	Modification Configuration	
Point of Interconnection	Stranger Creek 345 kV (532772)	Stranger Creek 345 kV (532772)	
Configuration/Capacity	151 x GE 2.0 MW = 302 MW	12 x GE 2.32 MW + 66 x GE 2.82 MW = 213.96 MW [dispatch] PPC in place to limit GEN-2016-149 & GEN-2016-150 combined POI injection to 604 MW	
Generation Interconnection Line	<u>GEN-2016-176 to GEN-2016-150 345 kV:</u> Length = 37 miles R = 0.001221 pu X = 0.017390 pu B = 0.339882 pu Rating MVA = 0 MVA	<u>GEN-2016-149 to GEN-2016-150 345 kV:</u> Length = 7.7 miles R = 0.000374 pu X = 0.003636 pu B = 0.071410 pu Rating MVA = 990 MVA	
Main Substation Transformer[1]	X = 8.997%, R = 0.225%, Winding MVA = 204 MVA, Rating MVA = 340 MVA	X = 8.497%, R = 0.212%, Winding MVA = 135 MVA, Rating MVA = 242 MVA	
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 151 X = 5.67%, R = 0.76%, Winding MVA = 347.3 MVA, Rating MVA = 347.3 MVA	Gen 1 Equivalent Qty: 12 X = 5.724%, R = 0.537%, Winding MVA = 30 MVA, Rating MVA = 34.8 MVA	Gen 2 Equivalent Qty: 66 X = 5.724%, R = 0.537%, Winding MVA = 184.8 MVA, Rating MVA = 214.5 MVA
Equivalent Collector Line[2]	R = 0.001841 pu X = 0.001682 pu B = 0.046781 pu	R = 0.006208 pu X = 0.012225 pu B = 0.134841 pu	
Generator Dynamic Model[3] & Power Factor	151 x GE 2.0 MW (GEWTGCU1)[3] Leading: 0.95 Lagging: 0.95	12 x GE 2.32 MW (GEWTG0705)[3] Leading: 0.9 Lagging: 0.9	66 x GE 2.82 MW (GEWTG0705)[3] Leading: 0.9 Lagging: 0.9
Reactive Power Devices	N/A	1 x 15 MVAR 34.5 kV Capacitor Bank	

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

Table ES-4: GEN-2016-174 Modification Request*

Facility	Existing Configuration	Modification Configuration*	
Point of Interconnection	Stranger Creek 345 kV (532772)	Stranger Creek 345 kV (532772)	
Configuration/Capacity	59 x GE 2.3 MW + 3 x GE 2.52 MW + 58 x GE 2.72 MW = 301.02 MW	59 x GE 2.3 MW + 3 x GE 2.52 MW + 58 x GE 2.72 MW = 301.02 MW [dispatch]	
Generation Interconnection Line	<u>GEN-2016-149 to GEN-2016-174:</u> Length = 38 miles R = 0.001208 pu X = 0.017664 pu B = 0.348080 pu Rating MVA = 1084 MVA	<u>Stranger Creek to Series Reactive Compensation:</u> Length = 37.22 miles R = 0.001183 pu X = 0.017298 pu B = 0.345170 pu Rating MVA = 1343 MVA	<u>Series Reactive Compensation to GEN-2016-174:</u> Length = 38.05 miles R = 0.001210 pu X = 0.017684 pu B = 0.345170 pu Rating MVA = 1343 MVA
Series Reactive Compensation	N/A	R = 0 pu X = -0.026465 pu B = 0 pu	
Reactive Power Devices	N/A	2 x 80 MVAR 345 kV Capacitor Bank 1 x 72 MVAR 345 kV Fixed Shunt Reactor	

*Only modified project facilities are shown in this table

SPP determined that steady-state analysis was not required because the modifications to the project were not significant enough to change the previously studied steady-state conclusions. However, SPP determined that while the modification used the same turbine manufacturer, GE, the change in stability model from GEWTGCU1 to GEWTG0705 required short circuit and dynamic stability analyses.

The addition of series compensation on the generation interconnection line may require a sub-synchronous resonance (SSR) and/or sub-synchronous control interactions (SSCI) study to evaluate if there could be resonant points under various operating scenarios that interact with existing generating facilities in the area. The Transmission Owner (TO) may determine additional analysis is needed.

The scope of this modification request study included reactive power analysis, short circuit analysis, and dynamic stability analysis.

Aneden performed the analyses using the modification request data and the DISIS-2017-002-1 study models:

- 2025 Summer Peak (25SP),
- 2025 Winter Peak (25WP)

All analyses were performed using the Siemens PTI PSS/E[1] version 34 software and the results are summarized below.

The results of the reactive power analysis using the 25SP model showed that the combined GEN-2016-149 & GEN-2016-150 project needed approximately 114 MVAr of compensation on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 79.3 MVAr found for the existing combined GEN-2016-149 & GEN-2016-150 configurations calculated using the DISIS-2017-002-1 model. In addition, the GEN-2016-174 project needed approximately 91.2 MVAr of compensation, an increase from the 55.1 MVAr found for the existing GEN-2016-174 configuration calculated using the DISIS-2017-002-1 model. 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 reactive power analysis is provided as information to the Interconnection Customer and TO and/or Transmission Operator (TOP). The applicable reactive power requirements will be further reviewed by the TO and/or TOP.

The short circuit analysis was performed for the projects with turbine changes, GEN-2016-149 & GEN-2016-150, using the 25SP stability model modified for short circuit analysis. The results from the short circuit analysis with the updated topology showed that the maximum GEN-2016-149 & GEN-2016-150 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2016-149 & GEN-2016-150 POI was no greater than 1.26 kA. The maximum three-phase fault current level within 5 buses of the POI with the GEN-2016-149 & GEN-2016-150 generators online was below 58 kA. There were several buses with a maximum three-phase fault current of over 40 kA. These buses are highlighted in Appendix B.

The dynamic stability analysis was performed using Siemens PTI PSS/E version 34.8.0 software for the two modified study models: 25SP and 25WP. 77 events were simulated, which included three-phase faults and single-line-to-ground stuck breaker faults.

[1] Power System Simulator for Engineering

The results of the dynamic stability analysis showed several existing base case issues that were found in both the original DISIS-2017-002-1 model and in the model with GEN-2016-149, GEN-2016-150, and GEN-2016-174 included. These issues were not attributed to the GEN-2016-149, GEN-2016-150, and GEN-2016-174 modification requests and are detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2016-149, GEN-2016-150, and GEN-2016-174 modification requests observed during the simulated faults. Additionally, the projects were found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

Based on the results of the study, SPP determined that the requested modification is not 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 GEN-2016-149 & GEN-2016-150 modification places the generating capacity of one 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.

SPP and Aneden recommend evaluating the series compensation via a sub-synchronous resonance (SSR) and/or sub-synchronous control interactions (SSCI) study to determine if there are any adverse interactions with existing generating facilities in the area.

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-2016-149, GEN-2016-150, and GEN-2016-174. A Modification Request Impact Study is a generation interconnection study performed to evaluate the impacts of modifying the DISIS study assumptions. The determination of the required scope of the study is dependent upon the specific modification requested and how it may impact the results of the DISIS study. Impacting the DISIS results could potentially affect the cost or timing of any Interconnection Request with a later Queue priority date, deeming the requested modification a Material Modification. The criteria sections below include reasoning as to why an analysis was either included or excluded from the scope of study.

All analyses were performed using the Siemens PTI PSS/E version 34 software. The results of each analysis are presented in the following sections.

1.1 Steady-State Analysis

Steady-state analysis is performed if SPP deems it necessary based on the nature of the requested change. SPP determined that steady-state analysis was not required because the modifications to the project were not significant enough to change the previously studied steady-state conclusions. A comparison between the real power output at the POI between the existing DISIS-2017-002-1 power flow model configuration and the requested modification configuration in the 25SP stability model was evaluated with all projects connected to the gen-tie dispatched at maximum.

1.2 Stability Analysis, Short Circuit Analysis

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

1.3 Reactive Power Analysis

SPP requires that a reactive power analysis be performed on the requested modification configuration as it is a non-synchronous resource. The reactive power 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-2016-149, GEN-2016-150, and GEN-2016-174 Interconnection Customer has requested a modification to these Generation Interconnection Requests (GIR) with a common Point of Interconnection (POI) at the Stranger Creek 345 kV Substation. At the time of report posting, GEN-2016-149, GEN-2016-150, and GEN-2016-174 are active Interconnection Requests with a queue status of "IA FULLY EXECUTED/ON SCHEDULE." These GIRs are wind farms with Energy Resource Interconnection Service (ERIS). GEN-2016-149 & GEN-2016-150 share a Generator Interconnection Agreement (GIA) and have a combined capacity of 604 MW, and GEN-2016-174 has a capacity of 302 MW.

There are four projects connected in series to the POI: GEN-2016-149, GEN-2016-174, GEN-2016-176 and GEN-2016-150 in that order.

The GEN-2016-149, GEN-2016-150, and GEN-2016-174 projects are currently in the DISIS-2016-002 cluster. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2016-149, GEN-2016-150, and GEN-2016-174 configuration using the DISIS-2017-002-1 stability models. The GEN-2016-149, GEN-2016-150, and GEN-2016-174 projects interconnect in the Evergy Kansas Central (WERE) control area. The projects details are shown in Table 2-1 below.

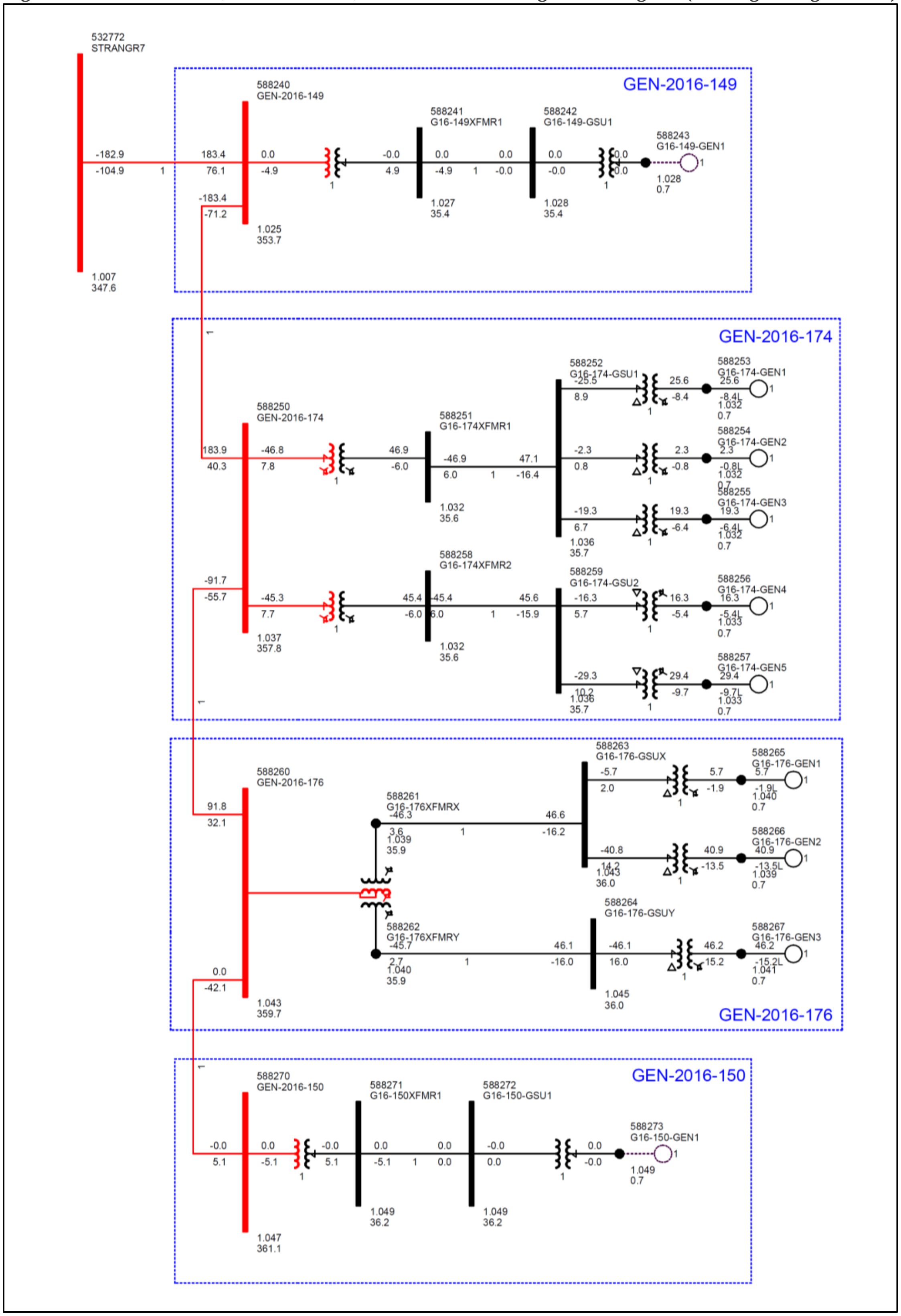
Table 2-1: GEN-2016-149, GEN-2016-150, & GEN-2016-174 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2016-149	Stranger Creek 345 kV (532772)	151 x GE 2.0 MW = 302 MW	302
GEN-2016-150	Stranger Creek 345 kV (532772)	151 x GE 2.0 MW = 302 MW	302
GEN-2016-174	Stranger Creek 345 kV (532772)	59 x GE 2.3 MW + 3 x GE 2.52 MW + 58 x GE 2.72 MW= 301.02 MW	302

This Study has been requested to evaluate the modification of the GEN-2016-149 turbine configuration to 12 x GE 2.32 MW + 4 x GE 2.52 MW + 139 x GE 2.82 MW (5 turbines reduced to 2.725 MW) for a total capacity of 429.9 MW and an assumed dispatch of 429.425 MW. The GEN-2016-150 turbine configuration has been modified to 12 x GE 2.32 MW + 66 x GE 2.82 MW for a total capacity and assumed dispatch of 213.96 MW. This generating capability for GEN-2016-149 & GEN-2016-150 (643.86 MW) exceeds its GIA Interconnection Service amount, 604 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. GEN-2016-174 did not have changes to the turbine configuration.

In addition, the GEN-2016-149 & GEN-2016-150 modification request included changes to the generation interconnection line configuration, collection systems, generator step-up transformers, main substation transformers, and reactive power devices. The GEN-2016-149 project was also relocated to be positioned just before GEN-2016-150 at the end of the gen-tie line. The GEN-2016-174 included the addition of a series capacitor to the generation interconnection line as well as a shunt reactor and capacitors at the main substation. Figure 2-2 shows the power flow model single line diagram for the GEN-2017-094 modification. The existing and modified configurations for GEN-2016-149, GEN-2016-150, and GEN-2016-174 are shown in Table 2-2, Table 2-3, and Table 2-4 respectively.

Figure 2-1: GEN-2016-149, GEN-2016-150, & GEN-2016-174 Single Line Diagram (Existing Configuration*)



*based on the DISIS-2017-002-1 25SP stability models

Figure 2-2: GEN-2016-149, GEN-2016-150, & GEN-2016-174 Single Line Diagram (Modification Configuration)

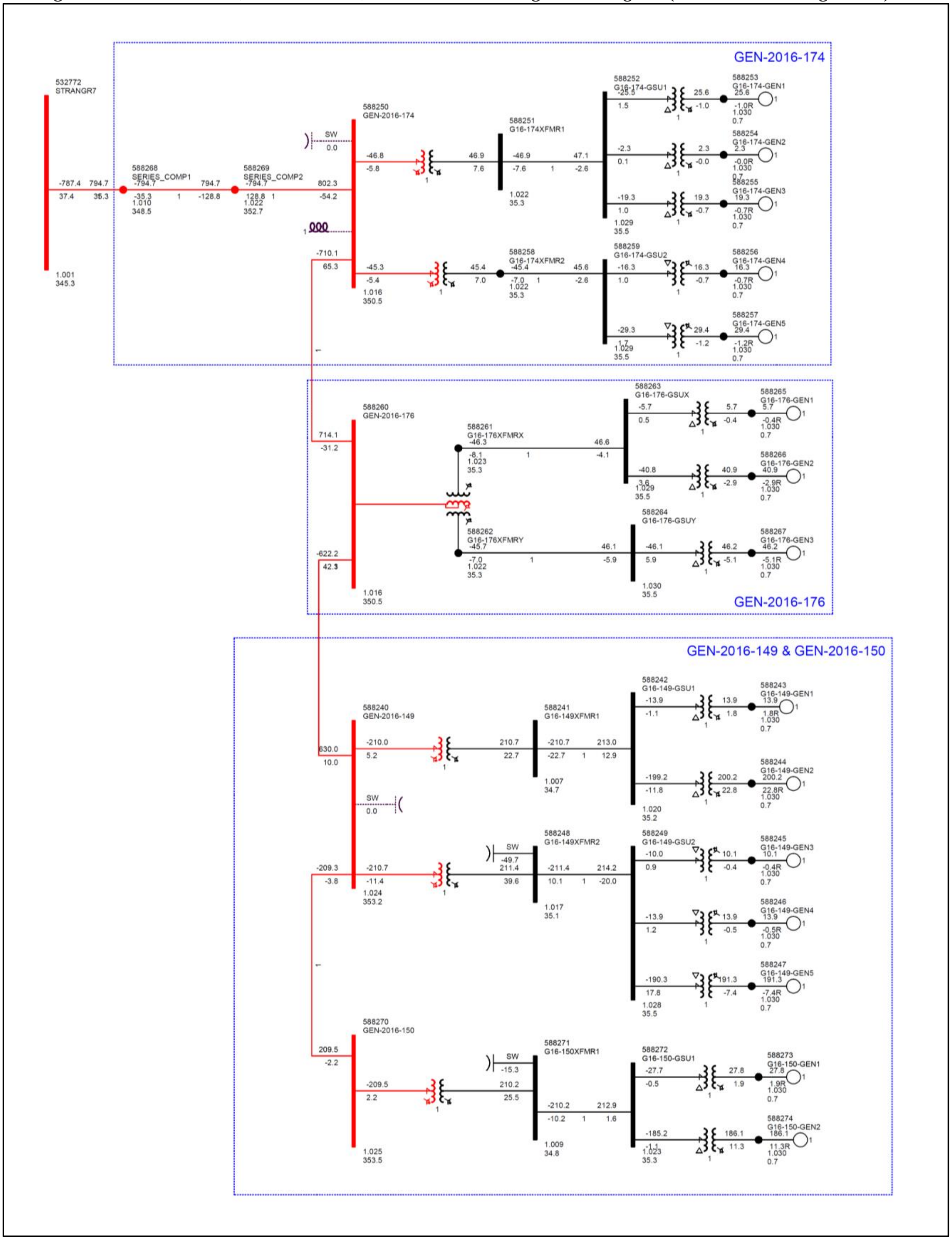


Table 2-2: GEN-2016-149 Modification Request

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<tr><th>Facility</th><th>Existing Configuration</th><th colspan="5">Modification Configuration</th></tr>
<tr><td>Point of Interconnection</td><td>Stranger Creek 345 kV (532772)</td><td colspan="5">Stranger Creek 345 kV (532772)</td></tr>
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<tr><td>Reactive Power Devices</td><td>N/A</td><td colspan="5">2 x 24 MVAR 34.5 kV Capacitor Bank
1 x 100 MVAR 345 kV Reactor</td></tr>
</table>

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

Table 2-3: GEN-2016-150 Modification Request

Facility	Existing Configuration	Modification Configuration	
Point of Interconnection	Stranger Creek 345 kV (532772)	Stranger Creek 345 kV (532772)	
Configuration/Capacity	151 x GE 2.0 MW = 302 MW	12 x GE 2.32 MW + 66 x GE 2.82 MW = 213.96 MW [dispatch] PPC in place to limit GEN-2016-149 & GEN-2016-150 combined POI injection to 604 MW	
Generation Interconnection Line	GEN-2016-176 to GEN-2016-150 345 kV: Length = 37 miles R = 0.001221 pu X = 0.017390 pu B = 0.339882 pu Rating MVA = 0 MVA	GEN-2016-149 to GEN-2016-150 345 kV: Length = 7.7 miles R = 0.000374 pu X = 0.003636 pu B = 0.071410 pu Rating MVA = 990 MVA	
Main Substation Transformer[1]	X = 8.997%, R = 0.225%, Winding MVA = 204 MVA, Rating MVA = 340 MVA	X = 8.497%, R = 0.212%, Winding MVA = 135 MVA, Rating MVA = 242 MVA	
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 151 X = 5.67%, R = 0.76%, Winding MVA = 347.3 MVA, Rating MVA = 347.3 MVA	Gen 1 Equivalent Qty: 12 X = 5.724%, R = 0.537%, Winding MVA = 30 MVA, Rating MVA = 34.8 MVA	Gen 2 Equivalent Qty: 66 X = 5.724%, R = 0.537%, Winding MVA = 184.8 MVA, Rating MVA = 214.5 MVA
Equivalent Collector Line[2]	R = 0.001841 pu X = 0.001682 pu B = 0.046781 pu	R = 0.006208 pu X = 0.012225 pu B = 0.134841 pu	
Generator Dynamic Model[3] & Power Factor	151 x GE 2.0 MW (GEWTGCU1)[3] Leading: 0.95 Lagging: 0.95	12 x GE 2.32 MW (GEWTG0705)[3] Leading: 0.9 Lagging: 0.9	66 x GE 2.82 MW (GEWTG0705)[3] Leading: 0.9 Lagging: 0.9
Reactive Power Devices	N/A	1 x 15 MVAR 34.5 kV Capacitor Bank	

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

Table 2-4: GEN-2016-174 Modification Request

Facility	Existing Configuration	Modification Configuration*	
Point of Interconnection	Stranger Creek 345 kV (532772)	Stranger Creek 345 kV (532772)	
Configuration/Capacity	59 x GE 2.3 MW + 3 x GE 2.52 MW + 58 x GE 2.72 MW = 301.02 MW	59 x GE 2.3 MW + 3 x GE 2.52 MW + 58 x GE 2.72 MW = 301.02 MW [dispatch]	
Generation Interconnection Line	GEN-2016-149 to GEN-2016-174: Length = 38 miles R = 0.001208 pu X = 0.017664 pu B = 0.348080 pu Rating MVA = 1084 MVA	Stranger Creek to Series Reactive Compensation: Length = 37.22 miles R = 0.001183 pu X = 0.017298 pu B = 0.345170 pu Rating MVA = 1343 MVA	Series Reactive Compensation to GEN-2016-174: Length = 38.05 miles R = 0.001210 pu X = 0.017684 pu B = 0.345170 pu Rating MVA = 1343 MVA
Series Reactive Compensation	N/A	R = 0 pu X = -0.026465 pu B = 0 pu	
Reactive Power Devices	N/A	2 x 80 MVAR 345 kV Capacitor Bank 1 x 72 MVAR 345 kV Fixed Shunt Reactor	

*Only modified project facilities are shown in this table

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-2017-002-1 study models. The analysis was completed using PSS/E version 34 software.

The methodology and results of the comparisons are described below.

3.1 POI Injection Comparison

The real power injection at the POI was determined using PSS/E to compare the DISIS-2017-002-1 power flow model configuration to the requested modifications for GEN-2016-149, GEN-2016-150, and GEN-2016-174 using the 25SP stability model. The percentage change in the POI injection was then evaluated.

SPP determined that power flow analysis was not required due to the insignificant change (increase of 1.61%) in the real power output at the POI between the DISIS-2017-002-1 power flow model configuration and requested modification shown in Table 3-1. The MW shown includes injections from GEN-2016-149, GEN-2016-150, and GEN-2016-174 as well as GEN-2016-176 which shares the gen-tie line. All four projects were dispatched to 100% of capacity in both the existing and modification models[2].

Table 3-1: POI Injection Comparison

Interconnection Request	Existing POI Injection (MW)	Modification POI Injection (MW)	POI Injection Difference %
GEN-2016-149, GEN-2016-150, & GEN-2016-174	1146.2*	1164.6*	1.61%

*The total MW amount includes the GEN-2016-176 project (dispatched to 100%) which shares the gen-tie line

3.2 Turbine Parameters Comparison

SPP determined that while the modification used the same turbine manufacturer, GE, the change in stability model from GEWTGCU1 to GEWTG0705 required short circuit and dynamic stability analysis. This is because the short circuit contribution and stability responses of the existing configuration and the requested modification's configuration may differ. The generator dynamic model for the modification can be found in Appendix A.

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

3.3 Equivalent Impedance Comparison Calculation

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

[2] Note that the projects were not dispatched to 100% in the starting models due the SPP fuel based dispatch

4.0 Reactive Power Analysis

The reactive power analysis was performed for GEN-2016-149, GEN-2016-150, and GEN-2016-174 to determine the capacitive charging effects during reduced generation conditions (unsuitable wind speeds, unsuitable solar irradiance, insufficient state of charge, idle conditions, curtailment, etc.) at the generation site and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

4.1 Methodology and Criteria

There are four projects connected in series to the POI: GEN-2016-174, GEN-2016-176, GEN-2016-149, and GEN-2016-150. A reactor size was determined for each project sequentially, starting with the GIR located closest to the POI while the radially connected systems were disconnected. Since GEN-2016-149 & GEN-2016-150 have a combined GIA, they were studied together in the modification model. For the project being studied, generators and reactive power devices were switched out of service while other system elements remained in-service. A shunt reactor was tested at the project's collection substation 34.5 kV bus to set the MVAr flow into the POI to approximately zero. The size of the shunt reactor is equivalent to the charging current value at unity voltage and the compensation provided is proportional to the voltage effects on the charging current (i.e., for voltages above unity, reactive compensation is greater than the size of the reactor).

Aneden performed the reactive power analysis using the modification request data based on the 25SP DISIS-2017-002-1 stability study model.

4.2 Results

The results from the analysis showed that the combined GEN-2016-149 & GEN-2016-150 project needed approximately 114 MVAr of compensation at its project substation to reduce the POI MVAr to zero. This is an increase from the 79.3 MVAr found for the existing combined GEN-2016-149 & GEN-2016-150 configurations calculated using the DISIS-2017-002-1 model. In addition, the GEN-2016-174 project needed approximately 91.2 MVAr of compensation. This is an increase from the 55.1 MVAr found for the existing GEN-2016-174 configuration calculated using the DISIS-2017-002-1 model. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the existing DISIS-2017-002-1 model. Figure 4-2 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the updated topology. The final shunt reactor requirements for GEN-2016-149, GEN-2016-150, and GEN-2016-174 are shown in Table 4-1. The results for GEN-2016-176 are not included in the table.

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

Table 4-1: Shunt Reactor Size for Reactive Power Study (Modification)

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)
			25SP
GEN-2016-149 & GEN-2016-150	532772	Stranger Creek 345 kV	114
GEN-2016-174	532772	Stranger Creek 345 kV	91.2

Note that there is a 100 MVAr 345 kV reactor at the GEN-2016-149 main substation and a 72 MVAr 345 kV reactor at the GEN-2016-174 main substation in the modification request that are not included in the analysis and results above.

Figure 4-1: GEN-2016-149, GEN-2016-150, & GEN-2016-174 Single Line Diagram Shunt Sizes (Existing DISIS)

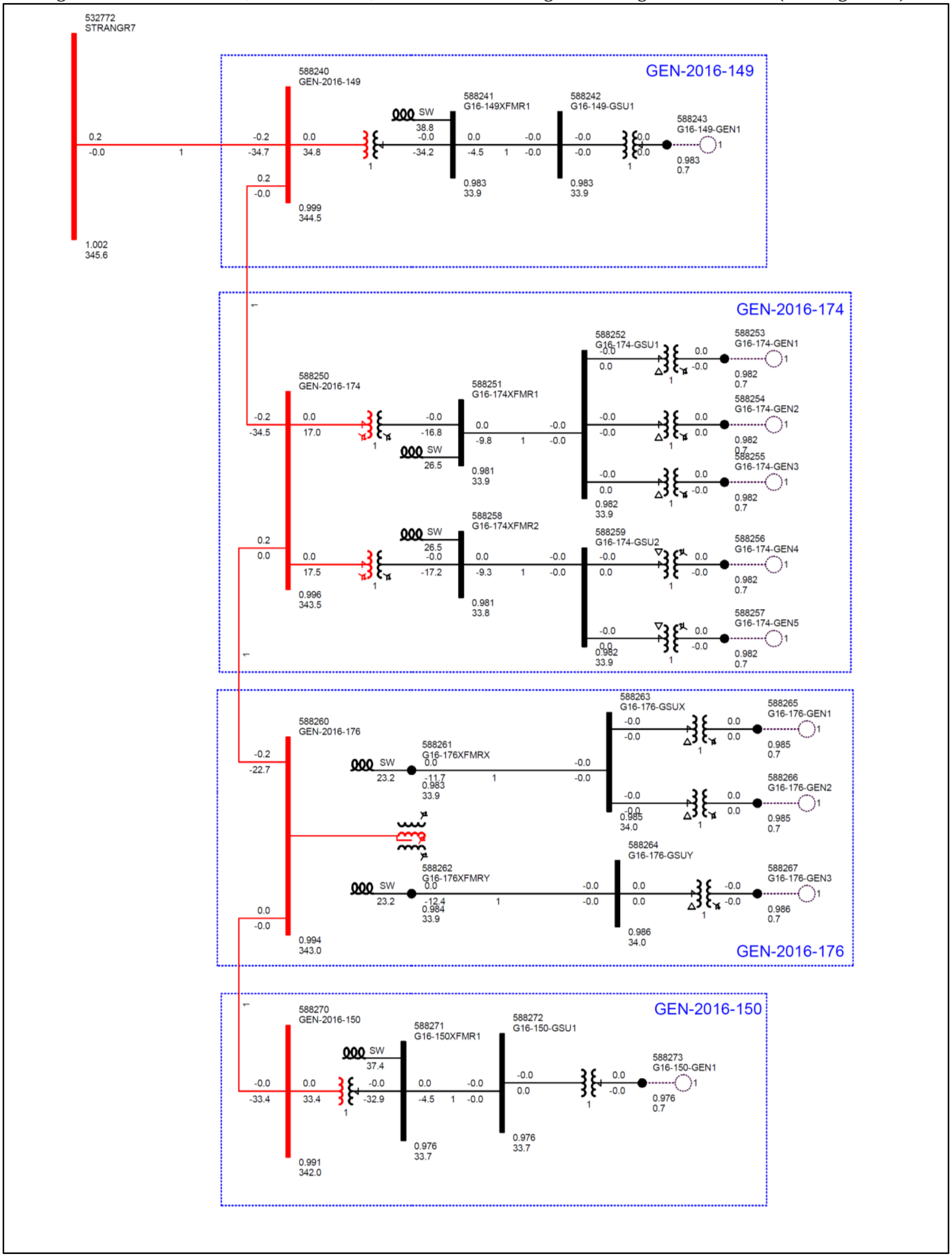
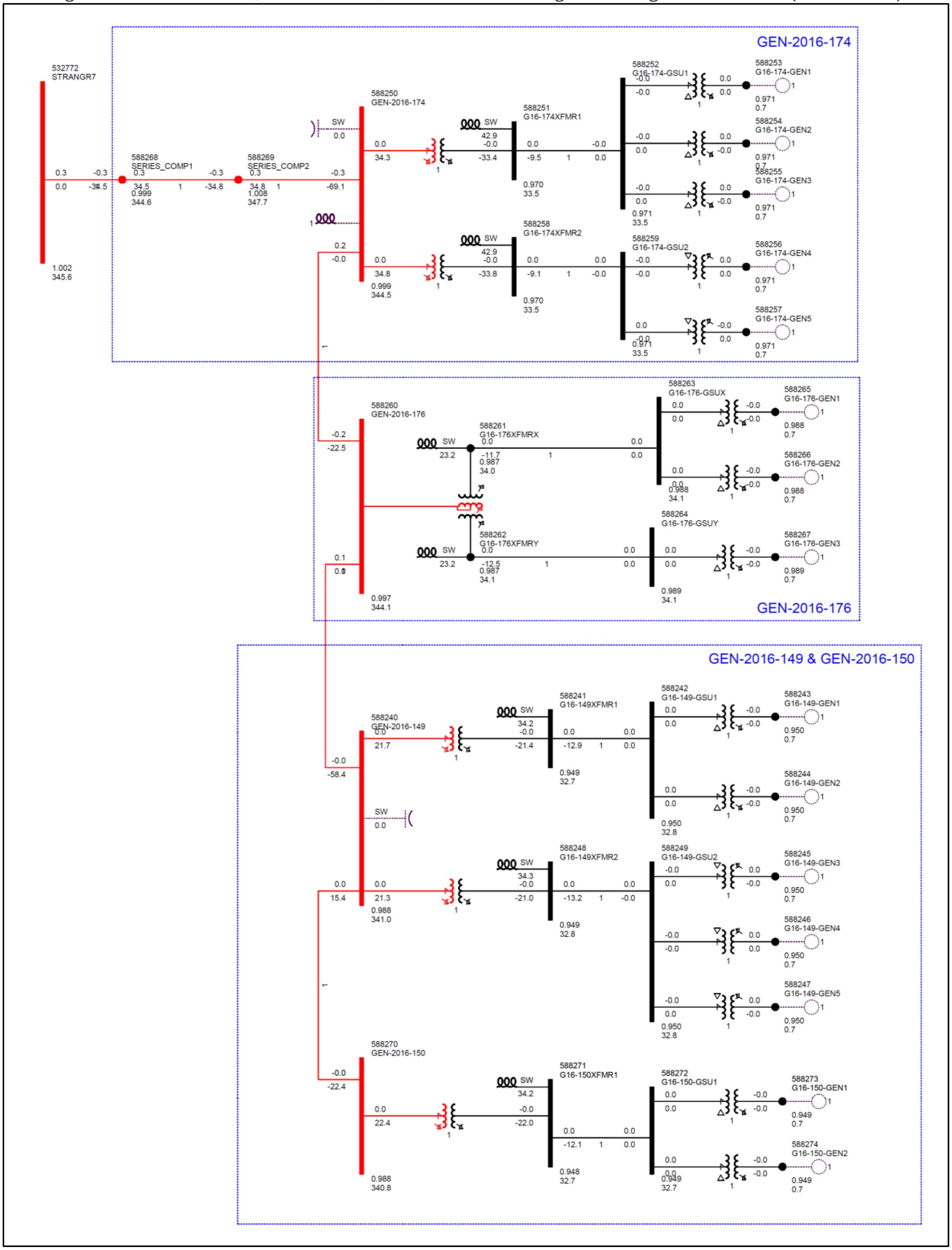


Figure 4-2: GEN-2016-149, GEN-2016-150, & GEN-2016-174 Single Line Diagram Shunt Sizes (Modification)



5.0 Short Circuit Analysis

A short circuit study was performed using the 25SP model for the projects with turbine configuration changes, GEN-2016-149 & GEN-2016-150. The detailed results of the short circuit analysis are provided in Appendix B.

5.1 Methodology

The short circuit analysis included applying a three-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 the projects with turbine configuration changes, GEN-2016-149 & GEN-2016-150, online.

Aneden created a short circuit model using the 25SP DISIS-2017-002-1 stability study model by adjusting the GEN-2016-149 & GEN-2016-150 short circuit parameters consistent with the modification data. The adjusted parameters used in the short circuit analysis are shown in Table 5-1 below. No other changes were made to the model.

Table 5-1: Short Circuit Model Parameters*

Parameter	Value by Generator Bus#						
	588243	588244	588245	588246	588247	588273	588274
Machine MVA Base	15.47	222.47	11.2	15.47	213.07	30.93	206.8
R (pu)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
X'' (pu)	0.2	0.2	0.2	0.2	0.2	0.2	0.2

*pu values based on Machine MVA Base

5.2 Results

The results of the short circuit analysis for the 25SP model are summarized in Table 5-2 and Table 5-3. The GEN-2016-149 & GEN-2016-150 POI bus (Stranger Creek 345 kV - 532772) fault current magnitudes are provided in Table 5-2 showing a fault current of 27.88 kA with the combined GEN-2016-149 & GEN-2016-150 project online. Table 5-3 shows the maximum fault current magnitudes and fault current increases with the combined GEN-2016-149 & GEN-2016-150 project online.

The maximum fault current calculated within 5 buses of the GEN-2016-149 & GEN-2016-150 POI (including the POI bus) was less than 58 kA for the 25SP model. There were several buses with a maximum three-phase fault current of over 40 kA. These buses are highlighted in Appendix B. The maximum GEN-2016-149 & GEN-2016-150 contribution to three-phase fault current was about 4.7% and 1.26 kA[3].

Table 5-2: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	kA Change	%Change
25SP	26.62	27.88	1.26	4.7%

[3] For buses not on the generation interconnection line

Table 5-3: 25SP Short Circuit Results[4]

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	9.37	0.01	0.1%
115	36.44	0.56	1.6%
161	57.57	0.18	0.4%
230	24.83	0.03	0.2%
345	30.65	1.26	4.7%
Max	**57.57**	**1.26**	**4.7%**

[4] For buses not on the generation interconnection line

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine configuration change and other modifications to GEN-2016-149, GEN-2016-150, and GEN-2016-174. The analysis was performed according to SPP's Disturbance Performance Requirements[5]. The modification details are described in Section 2.0 above and the dynamic modeling data for GEN-2016-149 & GEN-2016-150 is provided in Appendix A. The existing base case issues and simulation plots can be found in Appendix C.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested GEN-2016-149 turbine configuration of 12 x GE 2.32 MW + 4 x GE 2.52 MW + 139 x GE 2.82 MW (5 turbines reduced to 2.725 MW), and GEN-2016-150 turbine configuration of 12 x GE 2.32 MW + 66 x GE 2.82 MW. All turbines in the modified GEN-2016-149 & GEN-2016-150 configuration used the GEWTG0705 dynamic model. This stability analysis was performed using PTI's PSS/E version 34.8.0 software.

The modifications requested for the GEN-2016-149, GEN-2016-150, and GEN-2016-174 projects were used to create modified stability models for this impact study based on the DISIS-2017-002-1 stability study models:

- 2025 Summer Peak (25SP),
- 2025 Winter Peak (25WP)

The modified dynamic model data for the GEN-2016-149 & GEN-2016-150 project is provided in Appendix A. The modified power flow models and associated dynamic database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data. The dynamic model data for GEN-2016-174 did not change in this study.

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

- The WTDTA1 model at buses 534023, 579483, 579486, 760581, 760584, 541514, & 541518 were disabled to avoid numerical exceptions in SPD channels.
- The voltage protective relays at buses 539853, 539852, 539848, 539847, 539846, 539845, 760454, 762303, 541514, 635020, & 800103 were disabled to avoid generator tripping due to an instantaneous over voltage spike after fault clearing.
- The fault simulation file acceleration factor was reduced as needed to resolve stability simulation crashes.
- The REGCA1 model acceleration factor of the machines on buses 539845, 539846, 539847, 539848, 539852, & 539853 were changed to 0.01 to avoid simulation crashes.

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

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2016-149, GEN-2016-150, and GEN-2016-174 and other current and prior queued projects in their cluster group[6]. In addition, voltages of five (5) buses away from the POI of GEN-2016-149, GEN-2016-150, and GEN-2016-174 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 330 (AECI), 356 (AMMO), 515 (SWPA), 523 (GRDA), 524 (OKGE), 526 (SPS), 531 (MIDW), 534 (SUNC), 536 (WERE), 541 (KCPL), 544 (EMDE), and 635 (MEC) were monitored. The voltages of all 100 kV and above buses within the study area were monitored as well.

6.2 Fault Definitions

Aneden simulated the faults previously used for GEN-2016-149, GEN-2016-150, and GEN-2016-174 and developed additional fault events as required. The new set of faults was simulated using the modified study models. The fault events included three-phase faults and single-line-to-ground stuck breaker faults. Single-line-to-ground faults are approximated by applying a fault impedance to bring the faulted bus positive sequence voltage to 0.6 pu. The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 25SP and 25WP models.

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT08-3PH	P1	3 phase fault on the 87TH 7 (532775) to CRAIG 7 (542977) 345 kV line CKT 1, near 87TH 7. a. Apply fault at the 87TH 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.
FLT09-3PH	P1	3 phase fault on the STRANGR7 (532772) to 87TH 7 (532775) 345 kV line CKT 1, near STRANGR7. a. Apply fault at the STRANGR7 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.
FLT18-3PH	P1	3 phase fault on the JEC N 7 (532766) to GEARY 7 (532767) 345 kV line CKT 1, near JEC N 7. a. Apply fault at the JEC N 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.
FLT20-3PH	P1	3 phase fault on the HOYT 7 (532765) to JEC N 7 (532766) 345 kV line CKT 1, near HOYT 7. a. Apply fault at the HOYT 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.
FLT21-3PH	P1	3 phase fault on the HOYT 7 (532765) to STRANGR7 (532772) 345 kV line CKT 1, near HOYT 7. a. Apply fault at the HOYT 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.
FLT22-3PH	P1	3 phase fault on the JEC N 7 (532766) to MORRIS 7 (532770) 345 kV line CKT 1, near JEC N 7. a. Apply fault at the JEC N 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.

[6] Based on the DISIS-2017-002 Cluster Groups

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT29-3PH	P1	3 phase fault on the STRANGR7 (532772) to IATAN 7 (542982) 345 kV line CKT 1, near STRANGR7. a. Apply fault at the STRANGR7 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.
FLT30-3PH	P1	3 phase fault on the STRANGR7 (532772) to IATAN 7 (542982) 345 kV line CKT 2, near STRANGR7. a. Apply fault at the STRANGR7 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.
FLT34-3PH	P1	3 phase fault on the AUBURN 6 (532851) to JEC 6 (532852) 230 kV line CKT 1, near AUBURN 6. a. Apply fault at the AUBURN 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.
FLT77-3PH	P1	3 phase fault on the JARBALO3 (533244) to STRANGR3 (533268) 115 kV line CKT 1, near JARBALO3. a. Apply fault at the JARBALO3 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.
FLT78-3PH	P1	3 phase fault on the JARBALO3 (533244) to STRANGR3 (533268) 115 kV line CKT 2, near JARBALO3. a. Apply fault at the JARBALO3 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.
FLT82-3PH	P1	3 phase fault on the NW LEAV3 (533259) to STRANGR3 (533268) 115 kV line CKT 1, near NW LEAV3. a. Apply fault at the NW LEAV3 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.
FLT83-3PH	P1	3 phase fault on the STRANGR3 (533268) to THORNTN3 (533272) 115 kV line CKT 1, near STRANGR3. a. Apply fault at the STRANGR3 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.
FLT500-3PH	P1	3 phase fault on the NASHUA_CAP5 (541144) to NASHUA 5 (541203) 161 kV line CKT R, near NASHUA_CAP5. a. Apply fault at the NASHUA_CAP5 161 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.
FLT510-3PH	P1	3 phase fault on the ST JOE 7 (541199) to EASTOWN7 (541400) 345 kV line CKT 1, near ST JOE 7. a. Apply fault at the ST JOE 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.
FLT512-3PH	P1	3 phase fault on the ST JOE 7 (541199) to G17-183-TAP (761383) 345 kV line CKT 1, near ST JOE 7. a. Apply fault at the ST JOE 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.
FLT516-3PH	P1	3 phase fault on the NASHUA 5 (541203) to SMTHVL 5 (541204) 161 kV line CKT 1, near NASHUA 5. a. Apply fault at the NASHUA 5 161 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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT517-3PH	P1	3 phase fault on the NASHUA 5 (541203) to LBRTYWT5 (541247) 161 kV line CKT 1, near NASHUA 5. a. Apply fault at the NASHUA 5 161 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.
FLT518-3PH	P1	3 phase fault on the NASHUA 5 (541203) to NASHUA-5 (543028) 161 kV line CKT Z1, near NASHUA 5. a. Apply fault at the NASHUA 5 161 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.
FLT534-3PH	P1	3 phase fault on the PLTCTY 5 (541221) to WESTON 5 (541351) 161 kV line CKT 1, near PLTCTY 5. a. Apply fault at the PLTCTY 5 161 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.
FLT542-3PH	P1	3 phase fault on the RNRIDGE5 (541230) to NASHUA-5 (543028) 161 kV line CKT 1, near RNRIDGE5. a. Apply fault at the RNRIDGE5 161 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.
FLT551-3PH	P1	3 phase fault on the IND PRK5 (541256) to EASTOWN5 (541401) 161 kV line CKT 1, near IND PRK5. a. Apply fault at the IND PRK5 161 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.
FLT561-3PH	P1	3 phase fault on the IATAN5 (541350) to WESTON 5 (541351) 161 kV line CKT 1, near IATAN5. a. Apply fault at the IATAN5 161 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.
FLT562-3PH	P1	3 phase fault on the EASTOWN7 (541400) to IATAN 7 (542982) 345 kV line CKT 1, near EASTOWN7. a. Apply fault at the EASTOWN7 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.
FLT569-3PH	P1	3 phase fault on the W.GRDNR7 (542965) to CRAIG 7 (542977) 345 kV line CKT 1, near W.GRDNR7. a. Apply fault at the W.GRDNR7 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.
FLT580-3PH	P1	3 phase fault on the HAWTH 7 (542972) to NASHUA 7 (542980) 345 kV line CKT 1, near HAWTH 7. a. Apply fault at the HAWTH 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.
FLT588-3PH	P1	3 phase fault on the CRAIG 5 (542978) to PFLUMM 5 (542979) 161 kV line CKT 1, near CRAIG 5. a. Apply fault at the CRAIG 5 161 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.
FLT589-3PH	P1	3 phase fault on the CRAIG 5 (542978) to LENEXA 5 (543038) 161 kV line CKT 1, near CRAIG 5. a. Apply fault at the CRAIG 5 161 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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT591-3PH	P1	3 phase fault on the CRAIG 5 (542978) to COLLEGE5 (543048) 161 kV line CKT 1, near CRAIG 5. a. Apply fault at the CRAIG 5 161 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.
FLT592-3PH	P1	3 phase fault on the CRAIG 5 (542978) to CEDRCRK5 (543049) 161 kV line CKT 1, near CRAIG 5. a. Apply fault at the CRAIG 5 161 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.
FLT594-3PH	P1	3 phase fault on the NASHUA 7 (542980) to IATAN 7 (542982) 345 kV line CKT 1, near NASHUA 7. a. Apply fault at the NASHUA 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.
FLT595-3PH	P1	3 phase fault on the NASHUA 7 (542980) to G17-183-TAP (761383) 345 kV line CKT 1, near NASHUA 7. a. Apply fault at the NASHUA 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.
FLT609-3PH	P1	3 phase fault on the NASHUA-5 (543028) to SHOLCRK5 (543029) 161 kV line CKT 1, near NASHUA-5. a. Apply fault at the NASHUA-5 161 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.
FLT655-3PH	P1	3 phase fault on the CRAIG_CAP 5 (542945) to CRAIG 5 (542978) 161 kV line CKT R, near CRAIG_CAP 5. a. Apply fault at the CRAIG_CAP 5 161 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.
FLT713-3PH	P1	3 phase fault on the HOYT1 345 kV (532765) /115 kV (533163) /14.4 kV (532804) XFMR CKT 1, near HOYT 7 345 kV. a. Apply fault at the HOYT 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT714-3PH	P1	3 phase fault on the JEC-TX-13 345 kV (532766) /230 kV (532852) /14.4 kV (532805) XFMR CKT 1, near JEC N 7 345 kV. a. Apply fault at the JEC N 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT715-3PH	P1	3 phase fault on the JEC-TX-26 345 kV (532766) /230 kV (532852) /14.4 kV (532806) XFMR CKT 1, near JEC N 7 345 kV. a. Apply fault at the JEC N 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT720-3PH	P1	3 phase fault on the STRANGR TX-1 345 kV (532772) /115 kV (533268) /14.4 kV (532811) XFMR CKT 1, near STRANGR7 345 kV. a. Apply fault at the STRANGR7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT721-3PH	P1	3 phase fault on the STRANGR TX-3 345 kV (532772) /115 kV (533268) /14.4 kV (532816) XFMR CKT 1, near STRANGR7 345 kV. a. Apply fault at the STRANGR7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT725-3PH	P1	3 phase fault on the 87TH TX-1 345 kV (532775) /115 kV (533283) /13.8 kV (532818) XFMR CKT 1, near 87TH 7 345 kV. a. Apply fault at the 87TH 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT795-3PH	P1	3 phase fault on the CRAIG11 345 kV (542977) /161 kV (542978) /13.8 kV (543641) XFMR CKT 11, near CRAIG 7 345 kV. a. Apply fault at the CRAIG 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT796-3PH	P1	3 phase fault on the CRAIG22 345 kV (542977) /161 kV (542978) /13.8 kV (543642) XFMR CKT 22, near CRAIG 7 345 kV. a. Apply fault at the CRAIG 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT797-3PH	P1	3 phase fault on the CRAIG33 345 kV (542977) /161 kV (542978) /13.8 kV (543643) XFMR CKT 33, near CRAIG 7 345 kV. a. Apply fault at the CRAIG 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT798-3PH	P1	3 phase fault on the NASHUA11 345 kV (542980) /161 kV (543028) /13.8 kV (543640) XFMR CKT 11, near NASHUA7 345 kV. a. Apply fault at the NASHUA7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT799-3PH	P1	3 phase fault on the NASHUA12 345 kV (542980) /161 kV (543028) /13.8 kV (543639) XFMR CKT 12, near NASHUA7 345 kV. a. Apply fault at the NASHUA7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT801-3PH	P1	3 phase fault on the IATAN11 345 kV (542982) /161 kV (541350) /14.4 kV (541150) XFMR CKT 11, near IATAN11 345 kV. a. Apply fault at the IATAN11 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9001-3PH	P1	3 phase fault on the STRANGR7 (532772) to HOYT 7 (532765) 345 kV line CKT 1, near STRANGR7. a. Apply fault at the STRANGR7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on the IATAN 7 (542982) to NASHUA 7 (542980) 345 kV line CKT 1, near IATAN 7. a. Apply fault at the IATAN 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1	3 phase fault on the IATAN 7 (542982) to EASTOWN7 (541400) 345 kV line CKT 1, near IATAN 7. a. Apply fault at the IATAN 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.
FLT9004-3PH	P1	3 phase fault on the IATAN 2GSU 345 kV (542982) /24.5 kV (542962) XFMR CKT 1, near IATAN 7 345 kV. a. Apply fault at the IATAN 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer. Trip generator IAT G2 1 (542962)
FLT9005-3PH	P1	3 phase fault on the NASHUA 7 (542980) to HAWTH 7 (542972) 345 kV line CKT 1, near NASHUA 7. a. Apply fault at the NASHUA 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.
FLT9006-3PH	P1	3 phase fault on the EASTOWN7 (541400) to ST JOE 7 (541199) 345 kV line CKT 1, near EASTOWN7. a. Apply fault at the EASTOWN7 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
FLT9007-3PH	P1	3 phase fault on the EASTOWNE11 345 kV (541400) /161 kV (541401) /13.8 kV (541402) XFMR CKT 11, near EASTOWNE7 345 kV. a. Apply fault at the EASTOWNE7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9008-3PH	P1	3 phase fault on the CRAIG 7 (542977) to GEN-2017-224 (760431) 345 kV line CKT 1, near CRAIG 7. a. Apply fault at the CRAIG 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator G17-225-GEN1 (760454) 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 CRAIG 7 (542977) to W.GRDNR7 (542965) 345 kV line CKT 1, near CRAIG 7. a. Apply fault at the CRAIG 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.
FLT9010-3PH	P1	3 phase fault on the G17-183-TAP (671383) to GEN-2017-183 (761376) 345 kV line CKT 1, near G17-183-TAP. a. Apply fault at the G17-183-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generator G17-184GEN2 (761403), G17-183GEN1 (761379), G17-183GEN2 (761382), G17-184GEN1 (761400) c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9011-3PH	P1	3 phase fault on the NASHUA-5 (543028) to RNRIDGE5 (541230) 161 kV line CKT 1, near NASHUA-5. a. Apply fault at the NASHUA-5 161 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 EASTOWN5 (541401) to EAST 5 (541254) 161 kV line CKT 1, near EASTOWN5. a. Apply fault at the EASTOWN5 161 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9013-3PH	P1	3 phase fault on the WESTON 5 (541351) to PLTCTY 5 (541221) 161 kV line CKT 1, near WESTON 5. a. Apply fault at the WESTON 5 161 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9014-3PH	P1	3 phase fault on the EASTOWN5 (541401) to IND PRK5 (541256) 161 kV line CKT 1, near EASTOWN5. a. Apply fault at the EASTOWN5 161 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9015-3PH	P1	3 phase fault on the JEC 6 (532852) to AUBURN 6 (532851) 230 kV line CKT 1, near JEC 6. a. Apply fault at the JEC 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.
FLT9016-3PH	P1	3 phase fault on the JEC 6 (532852) to EMANHAT6 (532861) 230 kV line CKT 1, near JEC 6. a. Apply fault at the JEC 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.
FLT9017-3PH	P1	3 phase fault on the JEC 1 GSU 230 kV (532852) /26 kV (532651) XFMR CKT 1, near JEC 6 230 kV. a. Apply fault at the JEC 6 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer. Trip generator JEC U1 (532651)

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1001-SB	P4	**Stuck Breaker on at HOYT (532765) at 345kV bus** a. Apply single-phase fault at HOYT (532765) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the Bus HOYT (532765).
FLT1002-SB	P4	**Stuck Breaker on at 87TH 7 (532775) at 345kV bus** a. Apply single-phase fault at 87TH 7 (532775) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the Bus 87TH 7 (532775).
FLT1003-SB	P4	**Stuck Breaker on at IATAN 7 (542982) at 345kV bus** a. Apply single-phase fault at IATAN 7 (542982) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the IATAN 7 (542982) to NASHUA (542980) CKT 1 line. d. Trip the IATAN 7 (542982) to EASTOWN7 (541400) 345kV line CKT 1.
FLT1004-SB	P4	**Stuck Breaker on at IATAN 7 (542982) at 345kV bus** a. Apply single-phase fault at IATAN (542982) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the IATAN 7 (542982) to STRANGR7 (532772) CKT 1 line. d. Trip the IATAN 2 GSU 345 kV (542982) / 24.5 kV (542962) XFMR CKT 1. Trip generator IAT G2 1 (542962**)**
FLT1005-SB	P4	**Stuck Breaker on the STRANGR7 (532772) 345kV** a. Apply single-phase fault at the STRANGR7 345kV bus. b. After 16 cycles, trip the following elements c. Trip the STRANGR7 (532772) to HOYT 7 (532765) 345kV line CKT 1. d. Trip the STRANGR7 (532772) to 87TH 7 (532775) 345kV line CKT 1.
FLT1006-SB	P4	**Stuck Breaker on the STRANGR7 (532772) 345kV** a. Apply single-phase fault at the STRANGR7 345kV bus. b. After 16 cycles, trip the following elements c. Trip the STRANGR7 (532772) to HOYT 7 (532765) 345kV line CKT 1. d. Trip the STRANGR TX-1 345 kV (532772) /115 kV (533268) /14.4 kV (532811) XFMR CKT 1.
FLT1007-SB	P4	**Stuck Breaker on the STRANGR7 (532772) 345kV** a. Apply single-phase fault at the STRANGR7 345kV bus. b. After 16 cycles, trip the following elements c. Trip the STRANGR7 (532772) to IATAN 7 (542982) 345kV line CKT 2. d. Trip the STRANGR TX-3 345 kV (532772) /115 kV (533268) /14.4 kV (532816) XFMR CKT 1.
FLT1008-SB	P4	**Stuck Breaker on the STRANGR7 (532772) 345kV** a. Apply single-phase fault at the STRANGR7 345kV bus. b. After 16 cycles, trip the following elements c. Trip the STRANGR7 (532772) to IATAN 7 (542982) 345kV line CKT 2. d. Trip the STRANGR TX-1 345 kV (532772) /115 kV (533268) /14.4 kV (532811) XFMR CKT 1.
FLT1009-SB	P4	**Stuck Breaker on the STRANGR7 (532772) 345kV** a. Apply single-phase fault at the STRANGR7 345kV bus. b. After 16 cycles, trip the following elements c. Trip the STRANGR7 (532772) to IATAN 7 (542982) 345kV line CKT 1. d. Trip the STRANGR TX-3 345 kV (532772) /115 kV (533268) /14.4 kV (532816) XFMR CKT 1.
FLT1010-SB	P4	**Stuck Breaker on the STRANGR7 (532772) 345kV** a. Apply single-phase fault at the STRANGR7 345kV bus. b. After 16 cycles, trip the following elements c. Trip the STRANGR7 (532772) to IATAN 7 (542982) 345kV line CKT 1. d. Trip the STRANGR7 (532772) to 87TH 7 (532775) 345kV line CKT 1.
FLT1011-SB	P4	**Stuck Breaker on the STRANGR3 (533268) 115kV** a. Apply single-phase fault at the STRANGR3 115 kV bus. b. After 16 cycles, trip the following elements c. Trip the STRANGR3 (533268) to ARNOLD 3 (533211) 115kV line CKT 1. d. Trip the STRANGR3 (533268) to JARBALO3 (533244) 115kV line CKT 1.
FLT1012-SB	P4	**Stuck Breaker on the STRANGR3 (533268) 115kV** a. Apply single-phase fault at the STRANGR3 115kV bus. b. After 16 cycles, trip the following elements c. Trip the STRANGR TX-3 345 kV (532772) /115 kV (533268) /14.4 kV (532816) XFMR CKT 1. d. Trip the STRANGR3 (533268) to JARBALO3 (533244) 115kV line CKT 2.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1013-SB	P4	**Stuck Breaker on the STRANGR3 (533268) 115kV** a. Apply single-phase fault at the STRANGR3 115kV bus. b. After 16 cycles, trip the following elements c. Trip the STRANGR TX-1 345 kV (532772) /115 kV (533268) /14.4 kV (532811) XFMR CKT 1. d. Trip the STRANGR3 (533268) to NW LEAV3 (533259) 115kV line CKT 1.
FLT1014-SB	P4	**Stuck Breaker on at IATAN 7 (542982) at 345kV bus** a. Apply single-phase fault at IATAN (542982) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the IATAN11 345 kV (542982) /161 kV (541350) /14.4 kV (541150) XFMR CKT 11 d. Trip the IATAN 1 GSU 345 kV (542982) / 24.5 kV (542957) XFMR CKT 1. Trip generator IAT G1 1 (542957)

6.3 Results

Table 6-2 shows the relevant results of the fault events simulated for each of the modified models. Existing DISIS base case issues are documented separately in Appendix C. The associated stability plots are also provided in Appendix C.

Table 6-2: GEN-2016-149, GEN-2016-150, & GEN-2016-174 Dynamic Stability Results

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT08-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT09-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT18-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT20-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT21-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT22-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT29-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT30-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT34-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT77-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT78-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT82-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT83-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT500-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT510-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT512-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT516-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT517-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT518-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT534-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT542-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT551-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT561-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT562-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT569-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT580-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT588-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT589-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT591-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT592-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT594-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT595-3PH	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT609-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT655-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT713-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT714-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT715-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT720-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT721-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT725-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT795-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT796-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT797-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT798-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT799-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT801-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1012-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1013-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1014-SB	Pass	Pass	Stable	Pass	Pass	Stable

The results of the dynamic stability analysis showed several existing base case issues that were found in both the original DISIS-2017-002-1 model and the model with GEN-2016-149, GEN-2016-150, and GEN-2016-174 included. These issues were not attributed to the GEN-2016-149, GEN-2016-150, and GEN-2016-174 modification requests and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2016-149, GEN-2016-150, and GEN-2016-174 modification requests observed during the simulated faults. Additionally, the projects were found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

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.

The modified generating capacity of the combined GEN-2016-149 & GEN-2016-150 (643.86 MW) exceeds its GIA Interconnection Service amount, 604 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 making them and inform the Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Material Modification shall mean (1) modification to an Interconnection Request in the queue that has a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date; or (2) planned modification to an Existing Generating Facility that is undergoing evaluation for a Generating Facility Modification or Generating Facility Replacement, and has a material adverse impact on the Transmission System with respect to: i) steady-state thermal or voltage limits, ii) dynamic system stability and response, or iii) short-circuit capability limit; compared to the impacts of the Existing Generating Facility prior to the modification or replacement.

8.1 Results

SPP determined the requested modification is not a Material Modification based on the results and scope 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 steady-state conclusions.

SPP and Aneden recommend evaluating the series compensation via a sub-synchronous resonance (SSR) and/or sub-synchronous control interactions (SSCI) study to determine if there are any adverse interactions with existing generating facilities in the area.

This determination implies that any network upgrades already required by GEN-2016-149, GEN-2016-150, and GEN-2016-174 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.