Submitted to

Southwest Power Pool

Report On

GEN-2016-021
Modification Request Impact Study

Revision R1

Date of Submittal
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anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
04/20/2021	Aneden Consulting	Initial Report Issued.

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2016-021, an active generation interconnection request with a point of interconnection (POI) at the Hoskins 345 kV Substation.

The GEN-2016-021 project is proposed to interconnect in the Nebraska Public Power District (NPPD) control area with a capacity of 300 MW as shown in Table ES-1 below. This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2016-021 from the previously studied 150 x Vestas V110 2.0 MW to a turbine configuration of 51 x Siemens SG 5.0 MW + 18 x Siemens SWT 2.415 MW wind turbines for a total capacity of 298.47 MW. In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformers, the generation interconnection line, and reactive power devices. The configuration of the POI was modified to include the Turtle Creek 345 kV substation. Modeling updates for nearby Hoskins POI projects GEN-2015-007 and GEN-2016-043 were also included in the base models. The modification request changes for GEN-2016-021 are shown in Table ES-2.

Table ES-1: GEN-2016-021 Existing Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2016-021	300	150 x Vestas V110 2.0 MW	Hoskins 345 kV (640226)

Table ES-2: GEN-2016-021 Modification Request

<table>
<tr><th>Facility</th><th colspan="2">Existing</th><th colspan="3">Modification</th></tr>
<tr><td>Point of Interconnection</td><td colspan="2">Hoskins 345 kV (640226)</td><td colspan="3">Hoskins 345 kV (640226)</td></tr>
<tr><td>Configuration/Capacity</td><td colspan="2">150 x Vestas V110 2.0MW = 300 MW</td><td colspan="3">51 x Siemens SG 5.0 MW + 18 x Siemens SWT 2.415 MW = 298.47 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td colspan="2"><u>GEN-2016-021 to Hoskins</u>
Length = 36 miles
R = 0.003570 pu
X = 0.022940 pu
B = 0.242810 pu</td><td><u>GEN-2016-021 to Turtle Creek</u>
Length = 11.16 miles
R = 0.000612 pu
X = 0.005542 pu
B = 0.096022 pu</td><td colspan="2"><u>Turtle Creek to Hoskins</u>
Length = 6.16 miles
R = 0.000255 pu
X = 0.003000 pu
B = 0.052680 pu</td></tr>
<tr><td>Main Substation Transformers</td><td>X = 8.998% R = 0.205%, Winding MVA = 120 MVA, Rating MVA = 200 MVA</td><td>X = 8.998% R = 0.205%, Winding MVA = 120 MVA, Rating MVA = 200 MVA</td><td>X12 = 9.497% R12 = 0.23%, X23 = 2.849% R23 = 0.068%, X13 = 14.246% R13 = 0.34%, Winding MVA = 100 MVA, Rating MVA = 167 MVA</td><td colspan="2">X12 = 9.497% R12 = 0.23%, X23 = 2.849% R23 = 0.068%, X13 = 14.246% R13 = 0.34%, Winding MVA = 100 MVA, Rating MVA = 167 MVA</td></tr>
<tr><td>GSU Transformer</td><td colspan="2">Gen 1 Equivalent Qty: 150:
X = 7.759%, R = 0.799%, Winding MVA = 315 MVA, Rating MVA = 315 MVA</td><td>Gen 1 Equivalent Qty: 30:
X = 8.74%, R = 0.67%, Winding MVA = 165 MVA, Rating MVA = 165 MVA</td><td>Gen 2 Equivalent Qty: 18:
X = 8.74%, R = 0.67%, Winding MVA = 54 MVA, Rating MVA = 54 MVA</td><td>Gen 3 Equivalent Qty: 21:
X = 8.74%, R = 0.67%, Winding MVA = 115.5 MVA, Rating MVA = 115.5 MVA</td></tr>
<tr><td>Equivalent Collector Line</td><td colspan="2">R = 0.002263 pu
X = 0.003623 pu
B = 0.178140 pu</td><td>R = 0.009198 pu
X = 0.009019 pu
B = 0.100272 pu</td><td colspan="2">R = 0.010299 pu
X = 0.010116 pu
B = 0.105591 pu</td></tr>
<tr><td>Reactive Power Devices</td><td colspan="2">N/A</td><td>1 x 16 MVAR 34.5 kV Capacitor Bank</td><td colspan="2">1 x 10 MVAR 34.5 kV Reactor
1 x 16 MVAR 34.5 kV Capacitor Bank</td></tr>
</table>

SPP determined that power flow analysis should not be performed based on the POI MW injection decrease of 0.52%. However, SPP determined that the turbine change from Vestas to Siemens turbines 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 post-modification GEN-2015-088 DISIS-2016-002-2 Group 9 study models:

1. 2017 Winter Peak (2017WP),
2. 2018 Summer Peak (2018SP),
3. 2026 Summer Peak (2026SP),
4. 2017 GGS Winter Peak Case (2017WP_GGS),
5. 2018 GGS Summer Peak Case (2018SP_GGS), and
6. 2026 GGS Summer Peak Case (2026SP_GGS).

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

The results of the charging current compensation analysis performed using the 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak models showed that the GEN-2016-021 project needed either a 30.7 MVAr shunt reactor at the project 34.5 kV bus to reduce the 345 kV Turtle Creek MVAr to zero, or a 36.2 MVAr shunt reactor at the project 34.5 kV bus to reduce the 345 kV Hoskins MVAr to zero (with Hoskins POI projects GEN-2015-007 and GEN-2016-043 disconnected), a decrease from the 42.3 MVAr found in the DISIS 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 customer and Transmission Owner. SPP does not require additional reactive requirements based on the results of this analysis.

The results from the short circuit analysis with the updated topology showed that the maximum GEN-2016-021 contribution to three-phase fault currents in the immediate systems at or near GEN-2016-021 was not greater than 0.85 kA for the 2018SP and 2026SP models and 0.83 kA for the 2018SP and 2026SP GGS models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-021 generators online were below 43 kA for the 2018SP and 2026SP models, as well as the 2018SP and 2026SP GGS models.

The dynamic stability analysis was performed using the six DISIS-2016-002-2 models for 2017 Winter Peak, 2018 Summer Peak, 2026 Summer Peak, 2017 Winter Peak GGS, 2018 Summer Peak GGS, and 2026 Summer Peak GGS. Up to 76 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

[1] DISIS-2016-001-1 Definitive Interconnection System Impact Study Report, December 22, 2017

The results of the dynamic stability analysis showed that there were no damping or voltage recovery violations observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

The requested modification has been determined by SPP to not be a Material Modification. The requested modification does not have a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.

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-2016-021. A Modification Request Impact Study is a generation interconnection study performed to evaluate the impacts of modifying the DISIS study assumptions. The determination of the required scope of the study is dependent upon the specific modification requested and how it may impact the results of the DISIS study. Impacting the DISIS results could potentially affect the cost or timing of any Interconnection Request with a later Queue priority date, deeming the requested modification a Material Modification. The criteria sections below include reasoning as to why an analysis was either included or excluded from the scope of study.

All analyses were performed using the PTI PSS/E version 33.7 software. The post-modification GEN-2015-088 DISIS-2016-002-2 Group 9 models were used as the base models for this study. The results of each analysis are presented in the following sections.

1.1 Power Flow

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

1.2 Stability Analysis, Short Circuit Analysis

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

1.3 Charging Current Compensation Analysis

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

1.4 Study Limitations

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

2.0 Project and Modification Request

The GEN-2016-021 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the Hoskins 345 kV Substation. At the time of the posting of this report, GEN-2016-021 is an active IR with a queue status of “IA FULLY EXECUTED/ON SCHEDULE.” GEN-2016-021 is a wind farm, has a maximum summer and winter queue capacity of 300 MW, and has Energy Resource Interconnection Service (ERIS).

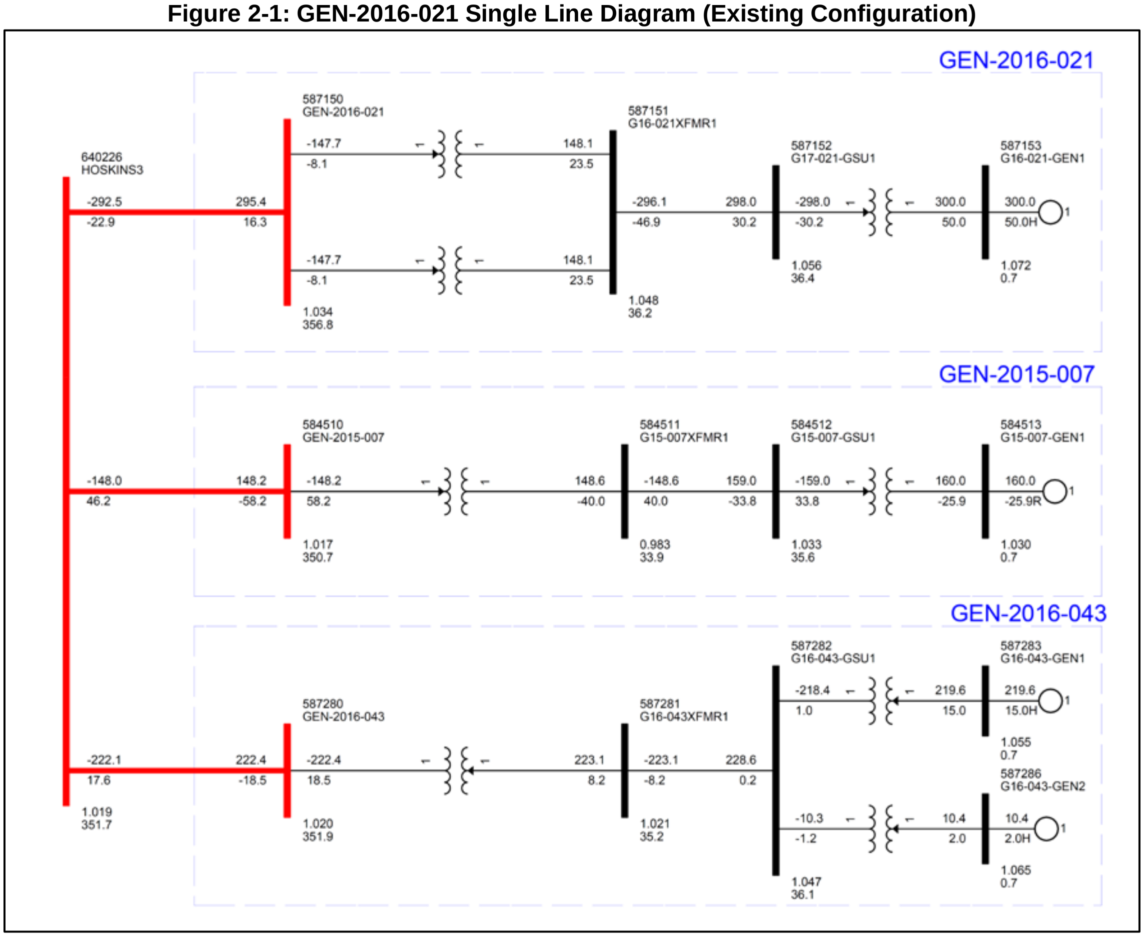
GEN-2016-021 was originally studied as part of Group 9 in the DISIS-2016-001 study. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2016-021 configuration.

The GEN-2016-021 project is proposed to interconnect in the Nebraska Public Power District (NPPD) control area with a combined nameplate capacity of 300 MW as shown in Table 2-1 below.

Table 2-1: GEN-2016-021 Existing Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2016-021	300	150 x Vestas V110 2.0 MW = 300 MW	Hoskins 345 kV (640226)

Figure 2-1: GEN-2016-021 Single Line Diagram (Existing Configuration)



This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2016-021 from the previously studied 150 x Vestas V110 2.0 MW to a turbine configuration of 51 x Siemens SG 5.0 MW + 18 x Siemens SWT 2.415 MW wind turbines for total capacity of 298.47 MW. In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformers, the generation interconnection line, and reactive power devices. Figure 2-2 below shows the reconfiguration of the POI to include the Turtle Creek 345 kV Substation and the re-termination of the GEN-2015-007, GEN-2016-021, and GEN-2016-043 at the Turtle Creek 345 kV Substation. Modeling updates for nearby Hoskins POI projects GEN-2015-007 and GEN-2016-043 were also included in the base models. The modification request changes for GEN-2016-021 are shown in Figure 2-2 and Table 2-2 below.

Figure 2-2: GEN-2016-021 Single Line Diagram (Modification Configuration)

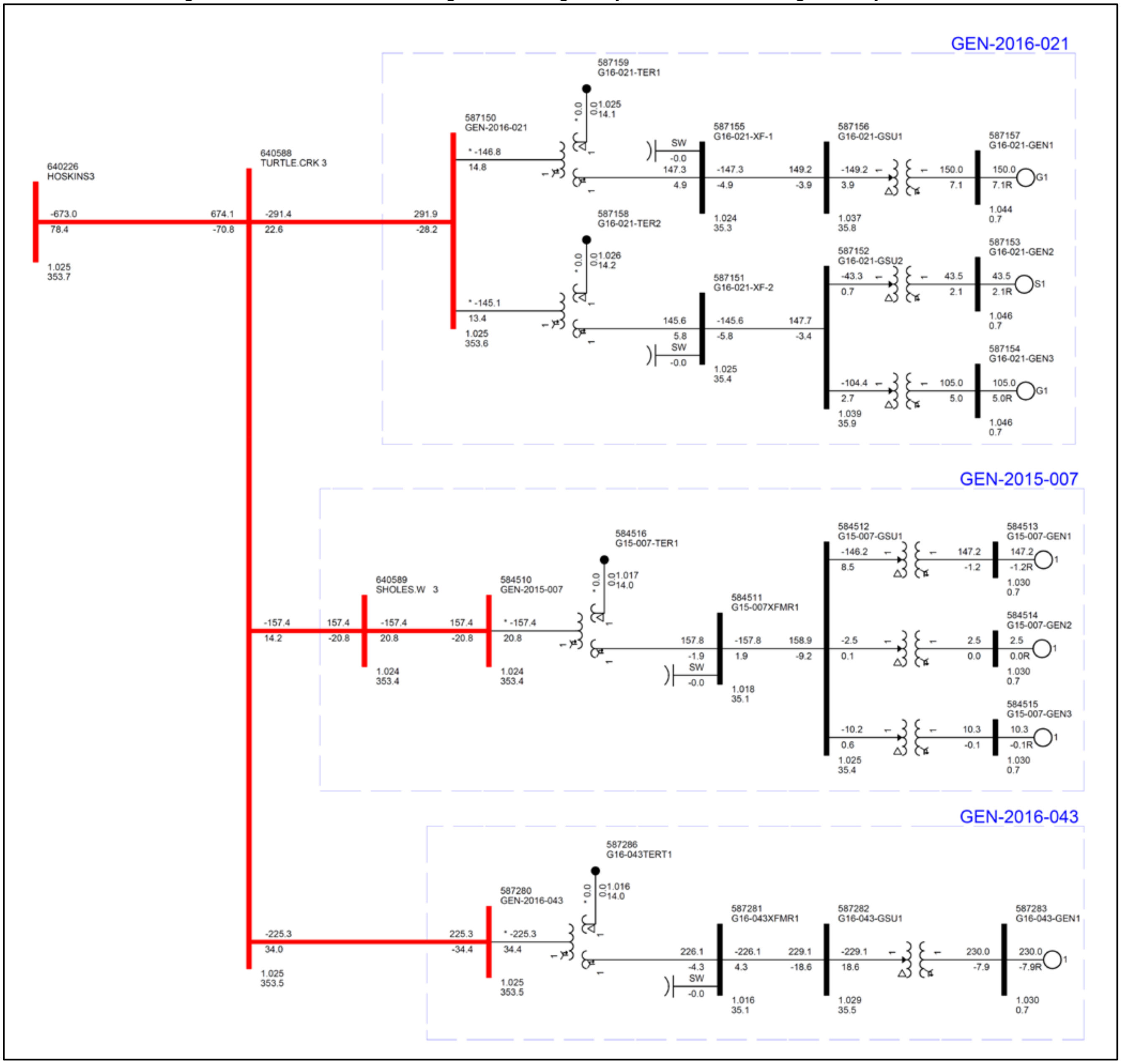


Table 2-2: GEN-2016-021 Modification Request

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X = 8.74%, R = 0.67%, Winding MVA = 54 MVA, Rating MVA = 54 MVA</td><td>Gen 3 Equivalent Qty: 21:
X = 8.74%, R = 0.67%, Winding MVA = 115.5 MVA, Rating MVA = 115.5 MVA</td></tr>
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1 x 16 MVAR 34.5 kV Capacitor Bank</td></tr>
</table>

3.0 Existing vs Modification Comparison

To determine which analysis is required, 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 post-modification GEN-2015-088 DISIS-2016-002-2 Group 9 study models.

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

3.1 POI Injection Comparison

The real power injection at the Hoskins 345 KV POI was determined using PSS/E for both the existing configuration and the requested modification with updates for GEN-2016-021. The percentage change in the POI injection before and after the modification request was then compared. If the MW difference was determined to be significant, power flow analysis would be performed to assess the impact of the modification request.

SPP determined that power flow analysis was not required due to the insignificant change (decrease of 0.52%) in the real power output at the POI between the existing configuration and requested modification shown in Table 3-1.

Table 3-1: GEN-2016-021 POI Injection Comparison

Interconnection Request	Existing POI Injection from Project (MW)	MRIS POI Injection from Project (MW)	POI Injection Difference from Project %
GEN-2016-021	292.5	291.0	-0.52%

3.2 Turbine Parameters Comparison

SPP determined that the turbine change from Vestas to Siemens turbines required short circuit and dynamic stability analyses as the 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 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-2016-021 to determine the capacitive charging effects during reduced generation conditions (unsuitable wind speeds, unsuitable solar irradiance, insufficient state of charge, idle conditions, curtailment, etc.) at the generation site and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

4.1 Methodology and Criteria

The GEN-2016-021 generators and capacitors (if any) were switched out of service while other collector 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 injection bus to approximately zero. Two reactor size calculations were performed, one to determine the amount needed to compensate for the flow into the 345 kV Turtle Creek bus, and one to determine the total amount needed to compensate for the flow into the 345 kV Hoskins bus with GEN-2015-007 and GEN-2016-043 disconnected. 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 reactor size calculated for the 345 kV Turtle Creek injection bus location was 30.7 MVAr, while the reactor size calculated for the 345 kV Hoskins injection bus location was 36.2 MVAr. Either reactor size is a decrease from the 42.3 MVAr found in the DISIS study[2]. Figure 4-1 illustrates the shunt reactor size needed to reduce the MVAr at the 345 kV Turtle Creek injection bus to approximately zero with the updated topology. Figure 4-2 illustrates the shunt reactor size needed to reduce the MVAr at the 345 kV Hoskins injection bus to approximately zero with the updated topology. The final shunt reactor requirements for GEN-2016-021 are shown in Table 4-1.

The information gathered from the charging current compensation analysis is provided as information to the customer and Transmission Owner. SPP does not require additional reactive requirements based on the results of this analysis.

Table 4-1: Shunt Reactor Size Based on Injection Location (Modification)

Machine	Injection Bus Number	Injection Bus Name	Reactor Size (MVAr)		
			17WP	18SP	26SP
GEN-2016-021	640588	Turtle Creek 345 kV	30.7	30.7	30.7
GEN-2016-021	640226	Hoskins 345 kV	36.2	36.2	36.2

[2] DISIS-2016-001-1 Definitive Interconnection System Impact Study Report, December 22, 2017

Figure 4-1: GEN-2016-021 Single Line Diagram (Modification Shunt Reactor - Turtle Creek)

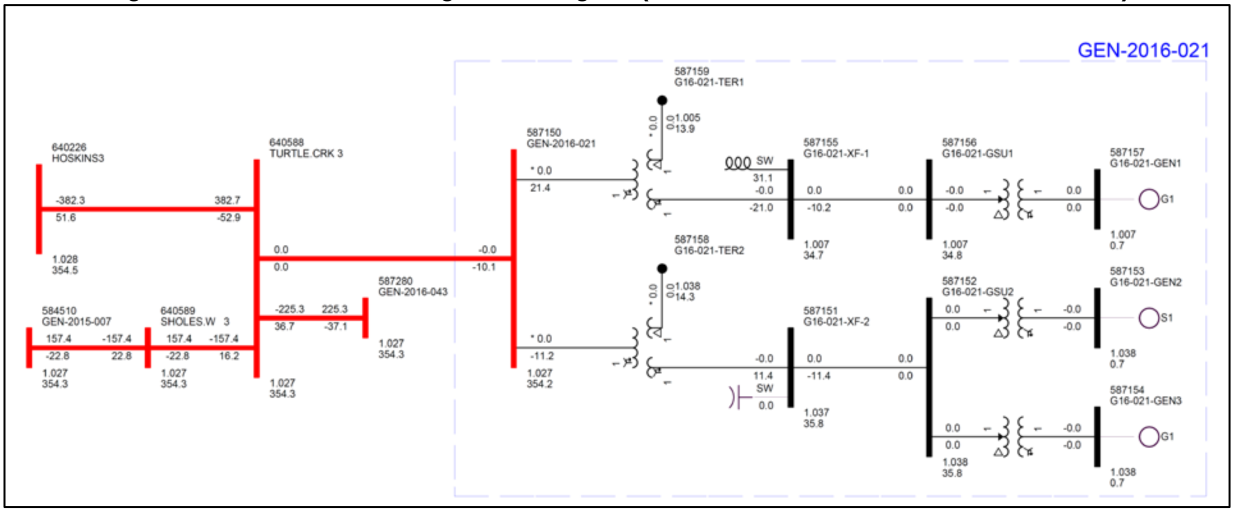
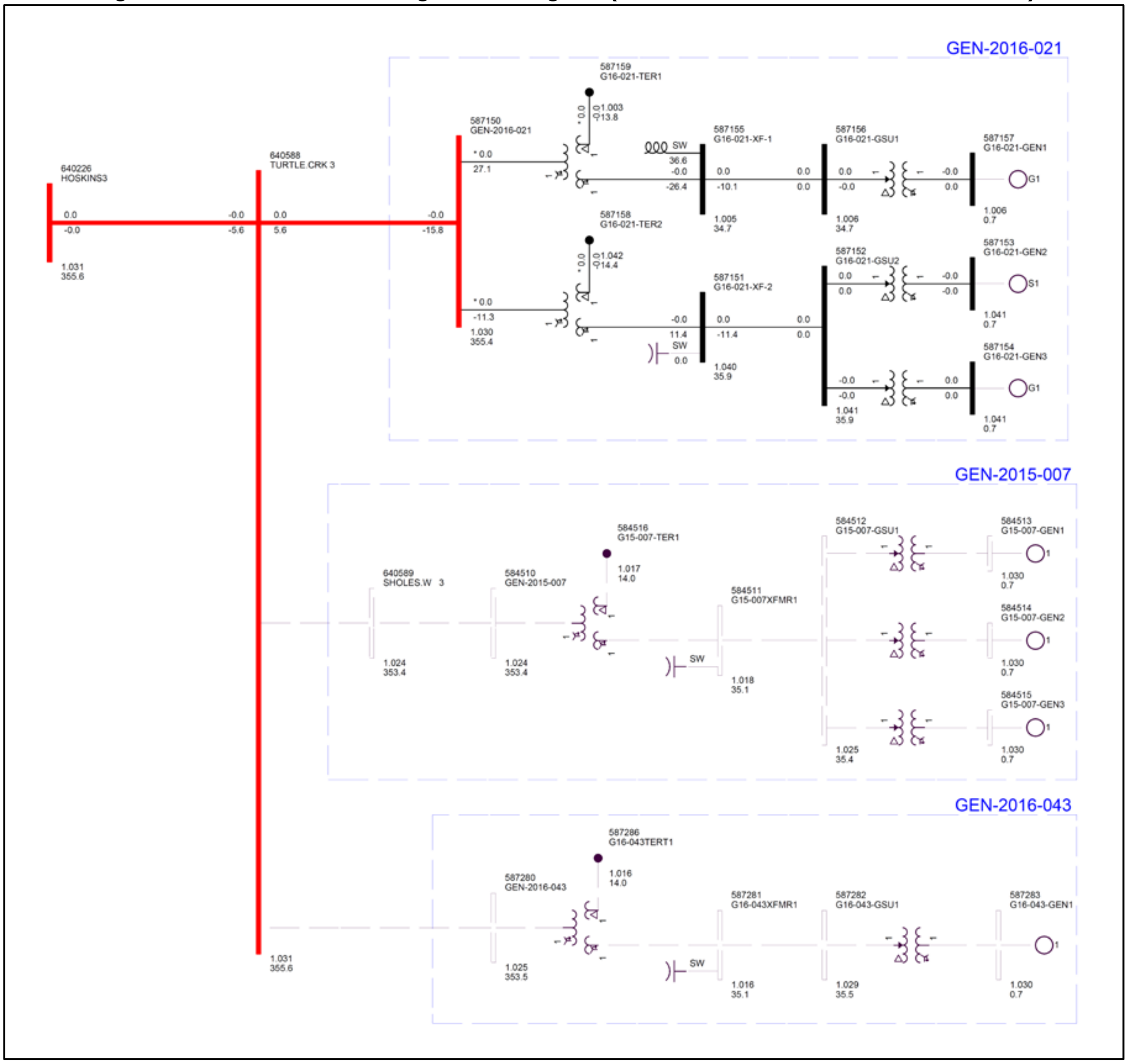


Figure 4-2: GEN-2016-021 Single Line Diagram (Modification Shunt Reactor - Hoskins)



5.0 Short Circuit Analysis

A short circuit study was performed using the 2018SP and 2026SP models along with the 2018SP and 2026SP GGS models for GEN-2016-021. 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 Hoskins 345 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels with and without GEN-2016-021 online.

5.2 Results

The results of the short circuit analysis for the 2018SP and 2026SP models are summarized in Table 5-1 through Table 5-3 respectively. The GEN-2016-021 POI bus fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 13.64 kA.

The maximum fault current calculated within 5 buses of the GEN-2016-021 POI was less than 43 kA for the 2018SP and 2026SP models respectively. The maximum GEN-2016-021 contribution to three-phase fault current was about 7.9% and 0.85 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2018SP	12.77	13.57	0.80	6.3%
2026SP	12.83	13.64	0.80	6.3%

Table 5-2: 2018SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	25.7	0.01	0.1%
115	36.2	0.34	1.8%
161	42.0	0.06	0.2%
230	20.2	0.21	2.0%
345	31.4	0.85	7.9%
Max	**42.0**	**0.85**	**7.9%**

Table 5-3: 2026SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	26.1	0.01	0.1%
115	36.5	0.33	1.8%
161	42.2	0.05	0.2%
230	20.0	0.20	2.0%
345	31.8	0.85	7.9%
Max	**42.2**	**0.85**	**7.9%**

The results of the short circuit analysis for the 2018SP and 2026SP GGS models are summarized in Table 5-4 through Table 5-6 respectively. The GEN-2016-021 POI bus fault current magnitudes are provided in Table 5-4 showing a maximum fault current of 13.58 kA.

The maximum fault current calculated within 5 buses of the GEN-2016-021 POI was less than 43 kA for the 2018SP and 2026SP GGS models respectively. The maximum GEN-2016-021 contribution to three-phase fault current was about 7.7% and 0.83 kA.

Table 5-4: POI GGS Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2018SP GGS	12.73	13.51	0.78	6.1%
2026SP GGS	12.80	13.58	0.78	6.1%

Table 5-5: 2018SP GGS Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	25.7	0.00	0.1%
115	36.1	0.31	1.7%
161	42.0	0.05	0.2%
230	20.2	0.19	1.9%
345	31.4	0.83	7.7%
Max	**42.0**	**0.83**	**7.7%**

Table 5-6: 2026SP GGS Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	26.1	0.00	0.1%
115	36.5	0.31	1.6%
161	42.2	0.05	0.2%
230	19.7	0.19	1.9%
345	31.8	0.83	7.7%
Max	**42.2**	**0.83**	**7.7%**

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine configuration change and other modifications to the GEN-2016-021 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 51 x Siemens SG 5.0 MW (GMD041308) + 18 x Siemens SWT 2.415 MW (SWTGU2) configuration for the GEN-2016-021 generating facilities. This stability analysis was performed using PTI's PSS/E version 33.7 software.

The stability models were developed using the post-modification GEN-2015-088 DISIS-2016-002-2 for Group 9 models. The modifications requested for the GEN-2016-021 project was used to create modified stability models for this impact study.

The modified dynamics model data for the DISIS-2016-001 Group 9 request, GEN-2016-021, 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-2016-021 and other equally and prior queued projects in Group 9. In addition, voltages of five (5) buses away from the POI of GEN-2016-021 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 534 (SUNC), 536 (WERE), 540 (GMO), 541 (KCPL), 635 (MEC), 640 (NPPD), 645 (OPPD), 650 (LES), and 652 (WAPA) 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-2016-021 and selected additional fault events for GEN-2016-021 as required. The new set of faults were simulated using the modified study models. The fault events included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers. The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 2017 Winter Peak, 2018 Summer Peak, and the 2026 Summer Peak models (including the GGS models).

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT89-3PH	P1	3 phase fault on the Hoskins (640226) to Antelope (640520) 345kV line circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT90-3PH	P1	3 phase fault on the Hoskins (640226) to Shell Creek (640342) 345kV line circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT91-3PH	P1	3 phase fault on the Hoskins (640226) to Raun (635200) 345kV line circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT92-3PH	P1	3 phase fault on the Hoskins 345/230/13.8kV (640226/640227/643082) transformer circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT93-3PH	P1	3 phase fault on the Hoskins 345/115/13.8kV (640226/640228/640231) transformer circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT94-3PH	P1	3 phase fault on the Raun (635200) to Sioux City (652564) 345kV line circuit 1, near Raun. a. Apply fault at the Raun 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT96-3PH	P1	3 phase fault on the Raun (635200) to S3451 (645451) 345kV line circuit 1, near Raun. a. Apply fault at the Raun 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT98-3PH	P1	3 phase fault on the Raun 345/161kV (635200/635201) transformer circuit 2, near Raun. a. Apply fault at the Raun 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT100-3PH	P1	3 phase fault on the Shell Creek (640342) to Columbus (640125) 345kV line circuit 1, near Shell Creek. a. Apply fault at the Shell Creek 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT101-3PH	P1	3 phase fault on the Shell Creek 345/230/13.8kV (640342/640343/643136) transformer circuit 1, near Shell Creek. a. Apply fault at the Shell Creek 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT102-3PH	P1	3 phase fault on the Antelope 345/115/13.8kV (640520/640521/640524) transformer circuit 1, near Antelope. a. Apply fault at the Antelope 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT103-3PH	P1	3 phase fault on the Hoskins 230/115/13.8kV (640227/640228/643083) transformer circuit 1, near Hoskins. a. Apply fault at the Hoskins 230kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.
FLT104-3PH	P1	3 phase fault on the Hoskins (640227) to G10-051-Tap (560347) 230kV line circuit 1, near Hoskins. a. Apply fault at the Hoskins 230kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
FLT106-3PH	P1	3 phase fault on the Hoskins (640228) to Belden (640080) 115kV line circuit 1, near Hoskins. a. Apply fault at the Hoskins 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT107-3PH	P1	3 phase fault on the Hoskins (640228) to Norfolk North (640296) 115kV line circuit 1, near Hoskins. a. Apply fault at the Hoskins 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
FLT108-3PH	P1	3 phase fault on the Hoskins (640228) to Stanton West (640363) 115kV line circuit 1, near Hoskins. a. Apply fault at the Hoskins 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
FLT89-PO1	P6	**Prior Outage of Hoskins 345 kV (640226) to Raun 345 kV (635200) line circuit 1;** 3 phase fault on Hoskins 345kV (640226) to Antelope 345kV (640520) line circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT90-PO1	P6	**Prior Outage of Hoskins 345 kV (640226) to Raun 345 kV (635200) line circuit 1;** 3 phase fault on Hoskins 345kV (640226) to Shell Creek 345kV (640342) line circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT93-PO1	P6	**Prior Outage of Hoskins 345 kV (640226) to Raun 345 kV (635200) line circuit 1;** 3 phase fault on Hoskins 345/115/13.8kV (640226/640228/640231) transformer circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT91-PO2	P6	**Prior Outage of Hoskins 345 kV (640226) to Antelope 345 kV (640520) line circuit 1;** 3 phase fault on Hoskins 345kV (640226) to Raun 345kV (635200) line circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT90-PO2	P6	**Prior Outage of Hoskins 345 kV (640226) to Antelope 345 kV (640520) line circuit 1;** 3 phase fault on Hoskins 345kV (640226) to Shell Creek 345kV (640342) line circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT93-PO2	P6	**Prior Outage of Hoskins 345 kV (640226) to Antelope 345 kV (640520) line circuit 1;** 3 phase fault on Hoskins 345/115/13.8kV (640226/640228/640231) transformer circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT89-PO3	P6	**Prior Outage of Hoskins 345/230/13.8 kV (640226/640227/643082) Transformer circuit 1;** 3 phase fault on Hoskins 345kV (640226) to Antelope 345kV (640520) line circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT90-PO3	P6	**Prior Outage of Hoskins 345/230/13.8 kV (640226/640227/643082) Transformer circuit 1;** 3 phase fault on Hoskins 345kV (640226) to Shell Creek 345kV (640342) line circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT91-PO3	P6	**Prior Outage of Hoskins 345/230/13.8 kV (640226/640227/643082) Transformer circuit 1;** 3 phase fault on Hoskins 345kV (640226) to Raun 345kV (635200) line circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9001-3PH	P1	3 phase fault on the Antelope (640520) to HOLT.CO3 (640510) 345kV line circuit 1, near Antelope. a. Apply fault at the Antelope 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9002-3PH	P1	3 phase fault on the HOLT.CO3 (640510) to GR ISLD-LNX3 (653871) 345kV line circuit 1, near HOLT.CO3. a. Apply fault at the HOLT.CO3 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9003-3PH	P1	3 phase fault on the HOLT.CO3 (640510) to THEDFORD3 (640500) 345kV line circuit 1, near HOLT.CO3. a. Apply fault at the HOLT.CO3 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9004-3PH	P1	3 phase fault on the HOLT.CO3 (640510) to G16-165-TAP (588344) 345kV line circuit 1, near HOLT.CO3. a. Apply fault at the HOLT.CO3 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9005-3PH	P1	3 phase fault on the HOLT.CO3 (640510) to GEN-2015-023 (584650) 345kV line circuit 1, near HOLT.CO3. a. Apply fault at the HOLT.CO3 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. Trip Generator G15-023-GEN1 (584653). Trip Generator G15-023-GEN2 (584656).
FLT9006-3PH	P1	3 phase fault on the Columbus (640125) to NW68HOLDRG3 (650114) 345kV line circuit 1, near Columbus. a. Apply fault at the Columbus 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9007-3PH	P1	3 phase fault on the Columbus 345/115/13.8kV (640125/640127/640129) transformer circuit 1, near Columbus 345kV. a. Apply fault at the Columbus 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9008-3PH	P1	3 phase fault on the Shell Creek (640343) to Columbus4 (640133) 230kV line circuit 1, near Shell Creek. a. Apply fault at the Shell Creek 230kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
FLT9009-3PH	P1	3 phase fault on the Columbus4 (640133) to MEADOWGROVE4 (640540) 230kV line circuit 1, near Columbus4. a. Apply fault at the Columbus4 230kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
FLT9010-3PH	P1	3 phase fault on the Columbus4 (640133) to E.COL.4 (640126) 230kV line circuit 1, near Columbus4. a. Apply fault at the Columbus4 230kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
FLT9011-3PH	P1	3 phase fault on the Columbus4 (640133) to COLMB.W4 (640131) 230kV line circuit 1, near Columbus4. a. Apply fault at the Columbus4 230kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
FLT9012-3PH	P1	3 phase fault on the Columbus4 230/115/13.2kV (640133/640134/640135) transformer circuit 1, near Columbus4 230kV. a. Apply fault at the Columbus4 230kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.
FLT9013-3PH	P1	3 phase fault on the RAUN (635200) to J412 POI (55201) 345kV line circuit 1, near RAUN. a. Apply fault at the RAUN 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9014-3PH	P1	3 phase fault on the RAUN (635200) to J506 POI (65400) 345kV line circuit 1, near RAUN. a. Apply fault at the RAUN 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9015-3PH	P1	3 phase fault on the RAUN 345/161/13.8kV (635200/635201/635205) transformer circuit 1, near RAUN 345kV. a. Apply fault at the RAUN 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9016-3PH	P1	3 phase fault on the RAUN (635200) 345kV to NEAL (635214) 24kV transformer circuit 1, near RAUN 345kV. a. Apply fault at the RAUN 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer. Trip Generator NEAL (635214).
FLT9017-3PH	P1	3 phase fault on the RAUN (635200) 345kV to NEAL (635213) 22kV transformer, near RAUN. a. Apply fault at the RAUN 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer. Trip Generator NEAL (635213).
FLT9018-3PH	P1	3 phase fault on the RAUN (635201) to NEAL (635202) 161kV line circuit 1, near RAUN. a. Apply fault at the RAUN 161kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
FLT9019-3PH	P1	3 phase fault on the RAUN (635201) to LIBERTY (635230) 161kV line circuit 1, near RAUN. a. Apply fault at the RAUN 161kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
FLT9020-3PH	P1	3 phase fault on the RAUN (635201) to TEKAMAH5 (640377) 161kV line circuit 1, near RAUN. a. Apply fault at the RAUN 161kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
FLT9021-3PH	P1	3 phase fault on the RAUN (635201) to NEAL (635203) 161kV line circuit 1, near RAUN. a. Apply fault at the RAUN 161kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
FLT9022-3PH	P1	3 phase fault on the RAUN (635201) to INTCHG (635220) 161kV line circuit 1, near RAUN. a. Apply fault at the RAUN 161kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
FLT9023-3PH	P1	3 phase fault on the J412 POI (55201) to IDA CO3 (635206) 345kV line circuit 1, near J412 POI. a. Apply fault at the J412 POI 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9024-3PH	P1	3 phase fault on the J506 POI (65400) to A345 (15010) 345kV line circuit 1, near J506 POI. a. Apply fault at the J506 POI 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. Trip Generator J506-B-GEN (16040). Trip Generator J506-B-GEN (15040).
FLT9025-3PH	P1	3 phase fault on the J506 POI (65400) to HIGHLND (635400) 345kV line circuit 1, near J506 POI. a. Apply fault at the J506 POI 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9026-3PH	P1	3 phase fault on the S3451 T3 345/161/13.8kV (645451/646251/648251) transformer circuit 1, near S3451 345kV. a. Apply fault at the S3451 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9027-3PH	P1	3 phase fault on the S3451 T3 (645451) to S3459 (645459) 345kV line circuit 1, near S3451. a. Apply fault at the S3451 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9028-3PH	P1	3 phase fault on the S3451 T3 (645451) to S3454 (645454) 345kV line circuit 1, near S3454. a. Apply fault at the S3451 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9029-3PH	P1	3 phase fault on the SIOUXCY 345/230/13.8kV (652564/652565/652305) transformer circuit 1, near SIOUXCY. a. Apply fault at the SIOUXCY 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9030-3PH	P1	3 phase fault on the SIOUXCY (652564) to SIOUXCY-LNX3 (652864) 345kV line circuit 1, near SIOUXCY. a. Apply fault at the SIOUXCY 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9031-3PH	P1	3 phase fault on the G10-051-Tap (560347) to TWIN CH4 (640386) 230kV line circuit 1, near G10-051-Tap. a. Apply fault at the G10-051-Tap 230kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
FLT9032-3PH	P1	3 phase fault on the G10-051-Tap (560347) to G10-051&1127 (580011) 230kV line circuit 1, near G10-051-Tap. a. Apply fault at the G10-051-Tap 230kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip Generator G10-051-GEN1 (580014) Trip Generator G10-051-GEN2 (580017) Trip Generator G10-051-GEN3 (580020) Trip Generator G11-027-GEN1 (580021) Trip Generator G11-027-GEN2 (580022) Trip Generator G11-027-GEN3 (580023)
FLT9033-3PH	P1	3 phase fault on the SIOUXCY4 (652565) to TWIN CH4 (640386) 230kV line circuit 1, near SIOUXCY4. a. Apply fault at the SIOUXCY4 230kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
FLT9034-3PH	P1	3 phase fault on the HOSKINS 115/34.5/13.8kV (640228/640229/643085) transformer, near HOSKINS. a. Apply fault at the HOSKINS 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted transformer.
FLT92-PO1	P6	**Prior Outage of Hoskins 345 kV (640226) to Raun 345 kV (635200) line circuit 1;** 3 phase fault on the Hoskins 345/230/13.8kV (640226/640227/643082) transformer circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT92-PO2	P6	**Prior Outage of Hoskins 345 kV (640226) to Antelope 345 kV (640520) line circuit 1;** 3 phase fault on the Hoskins 345/230/13.8kV (640226/640227/643082) transformer circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT93-PO3	P6	**Prior Outage of Hoskins 345/230/13.8 kV (640226/640227/643082) Transformer circuit 1;** 3 phase fault on Hoskins 345/115/13.8kV (640226/640228/640231) transformer, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT89-PO4	P6	**Prior Outage of Hoskins (640226) to Shell Creek (640342) 345kV line circuit 1;** 3 phase fault on the Hoskins (640226) to Antelope (640520) 345kV line circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT91-PO4	P6	**Prior Outage of Hoskins (640226) to Shell Creek (640342) 345kV line circuit 1;** 3 phase fault on the Hoskins (640226) to Raun (635200) 345kV line circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT92-PO4	P6	**Prior Outage of Hoskins (640226) to Shell Creek (640342) 345kV line circuit 1;** 3 phase fault on the Hoskins 345/230/13.8kV (640226/640227/643082) transformer circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT93-PO4	P6	**Prior Outage of Hoskins (640226) to Shell Creek (640342) 345kV line circuit 1;** 3 phase fault on the Hoskins 345/115/13.8kV (640226/640228/640231) transformer circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT1001-SB	P4	**Stuck Breaker on at Antelope (640520)** a. Apply single-phase fault at Antelope (640520) on the 345kV bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the bus Antelope (640520).

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT1002-SB	P4	**Stuck Breaker on at Shell Creek (640342)** a. Apply single-phase fault at Shell Creek (640342) on the 345kV bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the bus Shell Creek (640342).
FLT1003-SB	P4	**Stuck Breaker on at Raun (635200)** a. Apply single-phase fault at Raun (635200) on the 345kV bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the RAUN (635200) 345kV to NEAL (635213) 22kV transformer. Trip Generator NEAL (635213). d. Trip the Raun 345/161kV (635200/635201) transformer circuit 2.
FLT1004-SB	P4	**Stuck Breaker on at Raun (635200)** a. Apply single-phase fault at Raun (635200) on the 345kV bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the RAUN (635200) 345kV to NEAL (635214) 24kV transformer. Trip Generator NEAL (635214). d. Trip the RAUN 345/161/13.8kV (635200/635201/635205) transformer.
FLT1005-SB	P4	**Stuck Breaker on at Raun (635200)** a. Apply single-phase fault at Raun (635200) on the 345kV bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the Hoskins (640226) to Raun (635200) 345kV line circuit 1. d. Trip the Raun (635200) to S3451 (645451) 345kV line circuit 1.
FLT1006-SB	P4	**Stuck Breaker on at Raun (635200)** a. Apply single-phase fault at Raun (635200) on the 345kV bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the RAUN (635200) to J412 POI (55201) 345kV line circuit 1. d. Trip the RAUN (635200) to J506 POI (65400) 345kV line circuit 1.
FLT1007-SB	P4	**Stuck Breaker on at Hoskins (640226)** a. Apply single-phase fault at Hoskins (640226) on the 345kV bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the RAUN (635200) to Hoskins (640226) 345kV line circuit 1. d. Trip the Hoskins 345/230/13.8kV (640226/640227/643082) transformer circuit 1.
FLT1008-SB	P4	**Stuck Breaker on at Hoskins (640227)** a. Apply single-phase fault at Hoskins (640227) on the 230kV bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the bus Hoskins (640227).
FLT1009-SB	P4	**Stuck Breaker on at Hoskins (640228)** a. Apply single-phase fault at Hoskins (640228) on the 115kV bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the Hoskins 345/115/13.8kV (640226/640228/640231) transformer circuit 1. d. Trip the Hoskins 115/34.5/13.8kV (640228/640229/643086) transformer circuit 1. e. Trip the Hoskins (640228) to Stanton West (640363) 115kV line circuit 1. f. Trip the Hoskins (640228) to Norfolk (640298) 115kV line circuit 1.
FLT1010-SB	P4	**Stuck Breaker on at Hoskins (640228)** a. Apply single-phase fault at Hoskins (640228) on the 115kV bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the Hoskins 230/115/13.8kV (640227/640228/643083) transformer circuit 1. d. Trip the Hoskins 115/34.5/13.8kV (640228/640229/643085) transformer circuit 1. e. Trip the Hoskins (640228) to Belden (640080) 115kV line circuit 1. f. Trip the Hoskins (640228) to Norfolk North (640296) 115kV line circuit 1.

6.3 Results

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

Table 6-2: GEN-2016-021 Dynamic Stability Results

Fault ID	17WP & 17WP_GGS			18SP & 18SP_GGS			26SP & 26SP_GGS		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT89-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT90-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT91-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT92-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT93-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT94-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT96-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT98-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT100-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT101-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT102-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT103-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT104-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT106-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT107-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT108-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	17WP & 17WP_GGS			18SP & 18SP_GGS			26SP & 26SP_GGS		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9029-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9030-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9031-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9032-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9033-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9034-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT89-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT90-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT93-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT92-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT91-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT90-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT92-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT93-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT89-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT90-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT91-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT93-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT89-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT91-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT92-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT93-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

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

7.0 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.

7.1 Results

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

This determination implies that any network upgrades already required by GEN-2016-021 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.

8.0 Conclusions

The Interconnection Customer for GEN-2016-021 requested a Modification Request Impact Study to assess the impact of the turbine and facility changes to a configuration with a total of 51 x Siemens SG 5.0 MW + 18 x Siemens SWT 2.415 MW wind turbines for total capacity of 298.47 MW. In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformers, the generation interconnection line, and reactive power devices. The configuration of the POI was modified to include the Turtle Creek 345 kV substation. Modeling updates for nearby Hoskins POI projects GEN-2015-007 and GEN-2016-043 were also included in the base models.

SPP determined that power flow should not be performed based on the POI MW injection decrease of 0.52%. However, SPP determined that the turbine change from Vestas to Siemens turbines 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. The post-modification GEN-2015-088 DISIS-2016-002-2 Group 9 models were used as the base models for this study.

The results of the charging current compensation analysis performed using the 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak models showed that the GEN-2016-021 project needed either a 30.7 MVAr shunt reactor at the project 34.5 kV bus to reduce the 345 kV Turtle Creek MVAr to zero, or a 36.2 MVAr shunt reactor at the project 34.5 kV bus to reduce the 345 kV Hoskins MVAr to zero (with Hoskins POI projects GEN-2015-007 and GEN-2016-043 disconnected), a decrease from the 42.3 MVAr found in the DISIS study[3]. 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 customer and Transmission Owner. SPP does not require additional reactive requirements based on the results of this analysis.

The results from the short circuit analysis with the updated topology showed that the maximum GEN-2016-021 contribution to three-phase fault currents in the immediate systems at or near GEN-2016-021 was not greater than 0.85 kA for the 2018SP and 2026SP models and 0.83 kA for the 2018SP and 2026SP GGS models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-021 generators online were below 43 kA for the 2018SP and 2026SP models, as well as the 2018SP and 2026SP GGS models.

The dynamic stability analysis was performed using the six DISIS-2016-002-2 models for 2017 Winter Peak, 2018 Summer Peak, 2026 Summer Peak, 2017 Winter Peak GGS, 2018 Summer Peak GGS, and 2026 Summer Peak GGS. Up to 76 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

[3] DISIS-2016-001-1 Definitive Interconnection System Impact Study Report, December 22, 2017

The results of the dynamic stability analysis showed that there were no damping or voltage recovery violations observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

The requested modification has been determined by SPP to not be a Material Modification. The requested modification does not have a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.

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.