Submitted to
Southwest Power Pool

SPP Southwest Power Pool

Report On

GEN-2016-174 Modification Request Impact Study

Revision R1

Date of Submittal
September 14, 2020

anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
09/14/2020	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-2016-174, an active generation interconnection request with a point of interconnection (POI) at the Stranger Creek 345 kV Substation.

The GEN-2016-174 project is proposed to interconnect in the Evergy's Westar Energy (WERE) control area with a capacity of 302 MW as shown in Table ES-1 below. This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2016-174 from the previously studied 151 x GE 2.0MW to a turbine configuration of 59 x GE 2.3 MW + 3 x GE 2.52 MW + 58 x GE 2.72 MW wind turbines for total capacity of 301.02 MW. In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformers, and the generation interconnection line. The modification request changes are shown in Table ES-2 below.

Table ES-1: GEN-2016-174 Existing Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2016-174	302	151 x GE 2.0MW = 302 MW	Stranger Creek 345 kV (532772)

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

<table>
<tr><th>Facility</th><th colspan="2">Existing</th><th colspan="5">Modification</th></tr>
<tr><td>Point of Interconnection</td><td colspan="2">Stranger Creek 345 kV (532772)</td><td colspan="5">Stranger Creek 345 kV (532772)</td></tr>
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Length = 37 miles
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X = 0.017390 pu
B = 0.339882 pu</td><td>GEN-2016-149 generator substation - POI
Length = 38 miles
R = 0.001254 pu
X = 0.017860 pu
B = 0.349068 pu</td><td colspan="2">GEN-2016-174 generator substation - GEN-2016-149 generator substation
Length = 38 miles
R = 0.001209 pu
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B = 0.348080 pu</td><td colspan="3">GEN-2016-149 generator substation - POI
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<tr><td>Main Substation Transformer</td><td colspan="2">X = 9%, R = 0.225%, Winding 204 MVA, Rate 340 MVA</td><td colspan="3">X = 8.5%, R = 0.21%, Winding 102 MVA, Rating 170 MVA</td><td colspan="2">X = 8.5%, R = 0.21%, Winding 102 MVA, Rating 170 MVA</td></tr>
<tr><td>GSU Transformer</td><td colspan="2">Gen 1 Equivalent Qty: 151:
X = 5.7%, R = 0.76%, Rating 347.3 MVA</td><td>Gen 1 Equivalent Qty: 36:
X = 5.7%, R = 0.76%, Rating 82.8 MVA</td><td>Gen 2 Equivalent Qty: 3:
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X = 5.7%, R = 0.76%, Rating 64.4 MVA</td><td>Gen 4 Equivalent Qty: 23:
X = 5.7%, R = 0.76%, Rating 52.9 MVA</td><td>Gen 5 Equivalent Qty: 35:
X = 5.7%, R = 0.76%, Rating 98 MVA</td></tr>
<tr><td>Equivalent Collector Line</td><td colspan="2">R = 0.001841 pu
X = 0.001682 pu
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X = 0.022521 pu
B = 0.101414 pu</td><td colspan="2">R = 0.013982 pu
X = 0.024665 pu
B = 0.096593 pu</td></tr>
</table>

SPP determined that power flow should not be performed based on the POI injection decrease of 1.73%. However, SPP determined that a turbine parameter comparison and an impedance comparison should be performed to evaluate whether fault analysis and short-circuit analysis is appropriate.

The turbine changes were from GE turbines to GE turbines, but the modeling parameters of the dynamic stability models changed significantly. The modification request resulted in a change in the equivalent impedances from the point of interconnection to the generator step up transformers of approximately 23.5%. As such a dynamic stability analysis was deemed necessary and the scope of this modification request study was expanded from a charging current compensation analysis to include both short-circuit analysis and dynamic stability analysis.

Aneden performed the analyses using the modification request data based on the DISIS-2016-002 Group 13 study models:

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

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

The 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-2016-174 project needed 56.48 MVAr of reactor shunts on the 34.5 kV bus of the project substation, an increase from the 39.34 MVAr found in the pre-modification case. 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-2016-174 contribution to three-phase fault currents in the immediate systems at or near GEN-2016-174 was not greater than 1.14 kA for the 2018SP and 2026SP cases. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-174 generators online were below 57 kA for the 2018SP models and 2026SP models.

The dynamic stability analysis was performed using the three DISIS-2016-002 models 2017 Winter Peak, 2018 Summer Peak, 2026 Summer Peak. Up to 60 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

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

The requested modification has been determined by SPP to not be a Material Modification. The requested modification does not have a material impact on the cost or timing of any 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-2016-174. 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 PTI PSS/E version 33.7 software. The results of each analysis are presented in the following sections.

1.1 Power Flow

To determine whether power flow analysis is required, SPP evaluates the difference in the real power output at the POI between the 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 collection parameters and collector system impedance between the existing configuration and the requested modification. Fault analysis and short-circuit analysis would be required if either of 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 plant'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-2016-174 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the Stranger Creek 345 kV Substation. At the time of the posting of this report, GEN-2016-174 is an active IR with a queue status of "IA FULLY EXECUTED/ON SCHEDULE." GEN-2016-174 is a wind farm, has a maximum summer and winter queue capacity of 302 MW, and has Energy Resource Interconnection Service (ERIS).

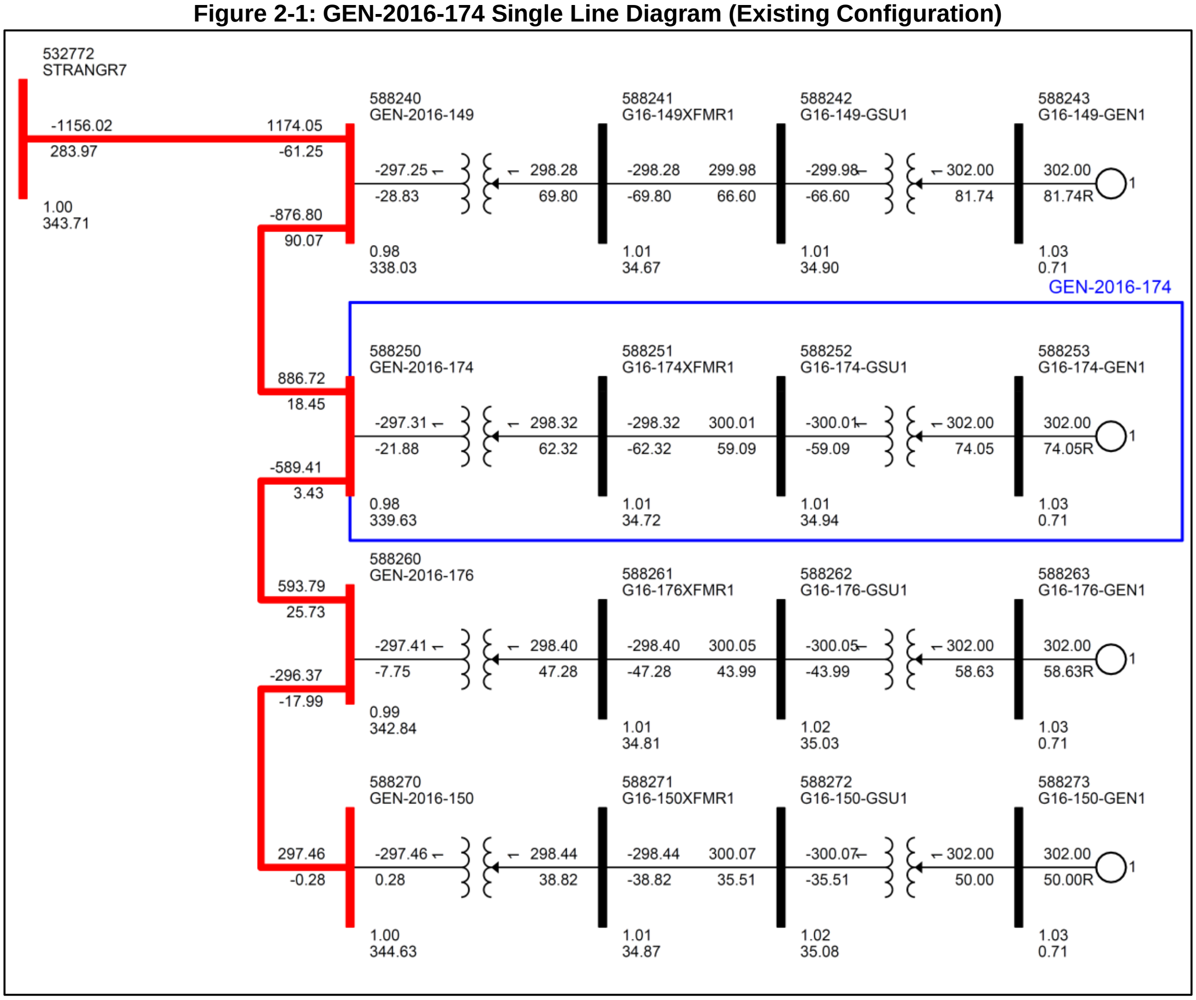
GEN-2016-174 was originally studied as part of Group 13 in the DISIS-2016-002 study. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2016-174 configuration.

The GEN-2016-174 project is proposed to interconnect in the Evergy's Westar Energy (WERE) control area with a combined nameplate capacity of 302 MW as shown in Table 2-1 below.

Table 2-1: GEN-2016-174 Existing Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2016-174	302	151 x GE 2.0MW = 302 MW	Stranger Creek 345 kV (532772)

Figure 2-1: GEN-2016-174 Single Line Diagram (Existing Configuration)



The GEN-2016-174 Modification Request included a turbine configuration change to a total of 59 x GE 2.3 MW + 3 x GE 2.52 MW + 58 x GE 2.72 MW wind turbines for total capacity of 301.02 MW. In addition, the modification request included changes to the collection system, generation step-up transformers, main substation transformers, and the generation interconnection line. The major modification request changes are shown in Figure 2-2 and Table 2-2 below.

Figure 2-2: GEN-2016-174 Single Line Diagram (New Configuration)

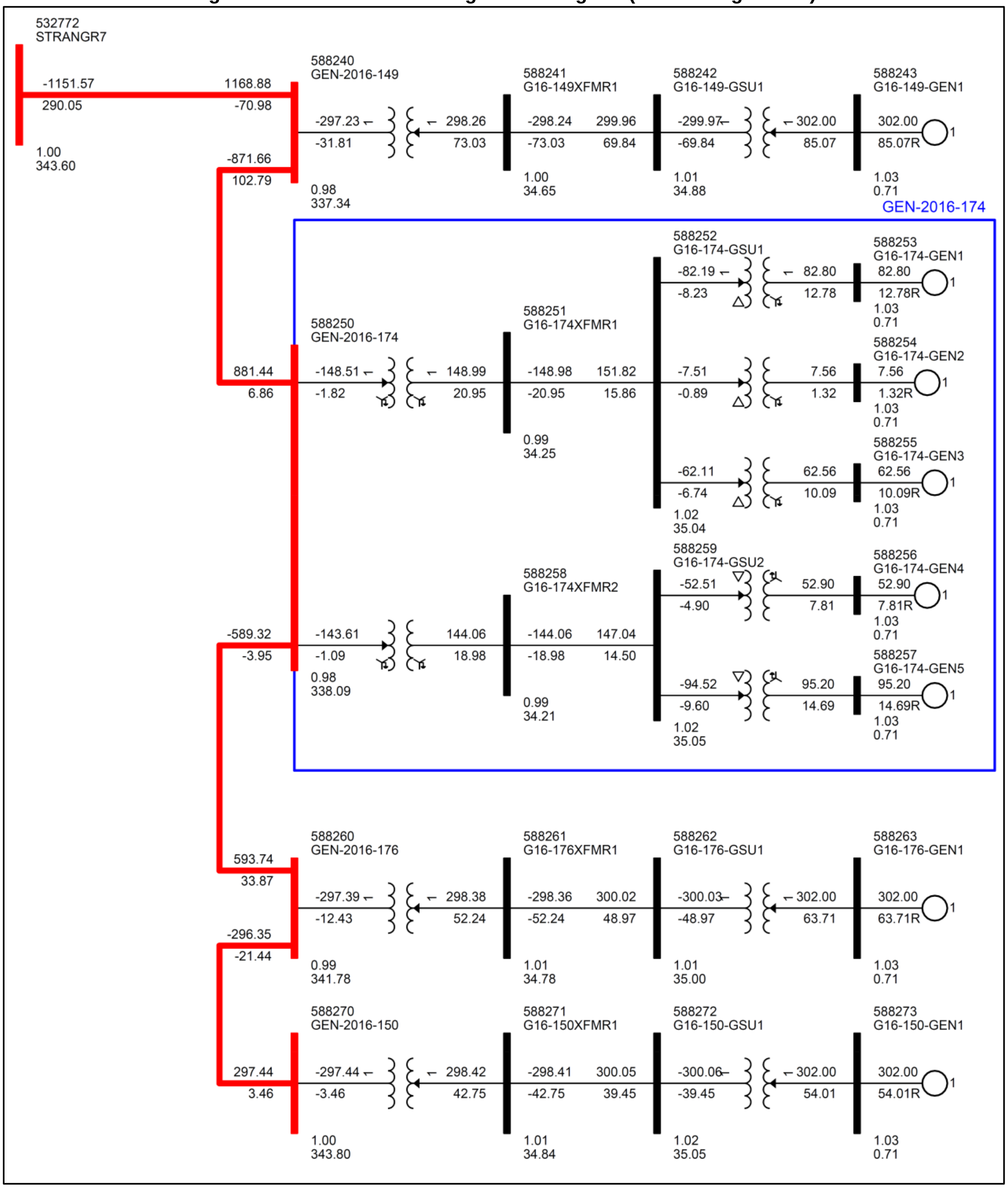


Table 2-2: GEN-2016-174 Modification Request

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3.0 Existing vs Modification Comparison

To determine whether stability 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 using the modification request data and the three DISIS-2016-002 Group 13 study models:

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

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 output at the POI was determined using PSS/E for both the existing configuration and the requested modification. 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 1.73%) in the real power output at the POI between the existing configuration and requested modification shown in Table 3-1.

Table 3-1: GEN-2016-174 POI Injection Comparison

Interconnection Request	Existing POI Injection from Project (MW)	MRIS POI Injection from Project (MW)	POI Injection Difference from Project %
GEN-2016-174	296.49	291.36	-1.73%

3.2 Turbine Parameters Comparison

The turbine dynamic stability models from the existing configuration and the requested modification were compared to determine if the change in modeling parameters was significant.

For the turbine collection, the turbine changes were from GE turbines to GE turbines, but the modeling parameters of the dynamic stability models did change significantly. The parameter differences are shown in Table 3-2. SPP determined that fault analysis and short-circuit analysis were required due to the change in turbines as the stability responses of the existing GE turbine and the requested modification's GE turbine may differ. The generator dynamic model for the modification can be found in Appendix A. The full parameter comparison can be found in Appendix B.

Table 3-2: Turbine Parameter Differences

Model Parameter	Existing	Modification		
	2.0MW	2.3MW	2.52MW	2.72MW
Tfv - V-regulator filter	0.15	0.5	0.50	0.50
KQi - MVAR/Volt gain	0.10	0.41	0.41	0.41
Kqd - Reactive droop gain	0.0000	0.0094	0.0300	0.0300
Qmax limit in WindFREE Mode	0.1200	0.1565	0.1429	0.1324
Qmin limit in WindFREE Mode	-0.1200	-0.1565	-0.1429	-0.1324

3.3 Equivalent Impedance Comparison Calculation

The impedances from all the components of the transmission lines, substation and step-up transformers, and equivalent collector line impedances were added in series for GEN-2016-174 before and after the modification request. The percentage increase in the impedances before and after the modification request were then compared. If the percentage increase was greater than 10%, additional dynamic stability analysis and short-circuit analysis would be performed to determine the impact of the requested modification. Table 3-3 shows the impedance differences before and after the modification request. Table 3-4 shows the increases in impedances from the original impedances to the modification request impedances.

Table 3-3: GEN-2016-174 Impedance Comparisons

System Component	Existing Model Impedances (p.u.)			Modification Request Impedances (p.u.)		
	R	*X*		*R*	*X*	
Gen Tie Line from POI to GEN-2016-174	0.00248	0.03525		0.00242	0.03533	
GEN-2016-174 collector system equivalent	0.00184	0.00168		0.01319	0.02356	
	R	*X*	*MVA Base*	*R*	*X*	*MVA Base*
GEN-2016-174 Main Transformer @ 100 MVA	0.00110	0.04410	100	0.00104	0.04165	100
GEN-2016-174 Unit GSU @ 100 MVA Base	0.0022	0.0164	100	0.00249	0.01865	100
	R	*X*	*Z*	*R*	*X*	*Z*
Total Impedance from POI to Collector System	0.007606	0.097447	0.097744	0.019135	0.119191	0.120717

Table 3-4: GEN-2016-174 Combined Impedance Comparison

Interconnection Request	Existing Impedance Z (p.u.)	MRIS Impedance Z (p.u.)	Impedance Change Z (p.u.)
GEN-2016-174	9.77%	12.07%	23.50%

SPP determined that the change in impedance (23.5%) and the change in modeling parameters have the potential to alter the project impact and would require fault analysis and short-circuit analysis to be performed to determine the impact of the requested modification.

4.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for 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-2016-149, GEN-2016-174, GEN-2016-176, and GEN-2016-150. A reactor size was determined for each project sequentially, starting with GEN-2016-149 while the radially connected systems were disconnected. For the project being studied, the 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 collection substation 34.5 kV bus to set the MVAr flow into the POI to approximately zero. The size of the shunt reactor is equivalent to the charging current value at unity voltage and the compensation provided is proportional to the voltage effects on the charging current (i.e. for voltages above unity, reactive compensation is greater than the size of the reactor).

4.2 Results

The results from the analysis showed that the GEN-2016-174 project needed an approximately 56.48 MVAr shunt reactor at the project substation, to reduce the POI MVAr to zero. Figure 4-2 illustrates the shunt reactor size needed for all four projects to reduce the POI MVAr to approximately zero. This is an increase from the 39.34 MVAr found in the pre-modification cases as shown in Figure 4-1. The final shunt reactor requirement for GEN-2016-174 is 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 for Low Wind Study

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)		
			17WP	18SP	26SP
GEN-2016-174	532772	Stranger Creek 345 kV	56.48	56.48	56.48

Figure 4-1: GEN-2016-174 Single Line Diagram (Existing Shunt Reactor)

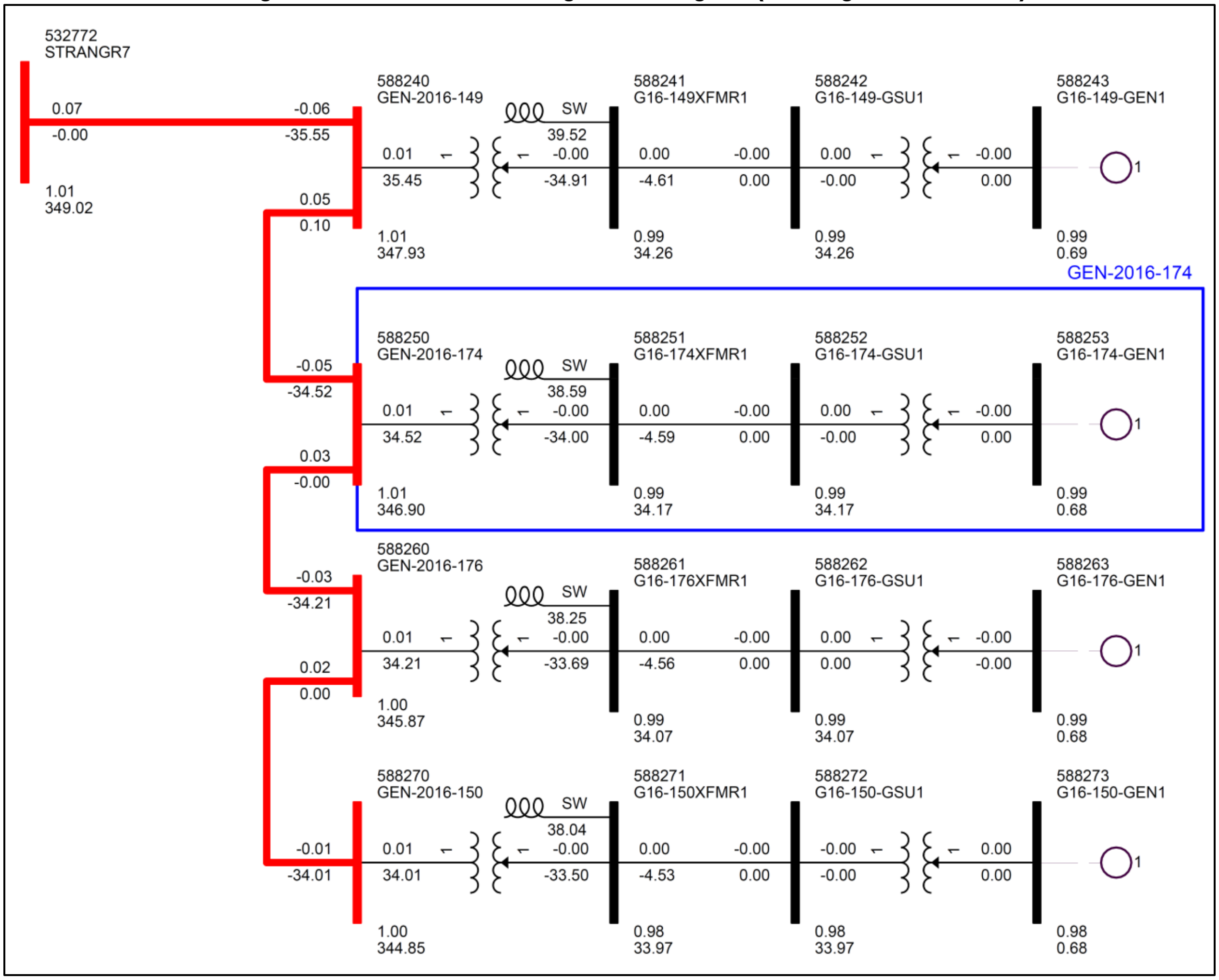
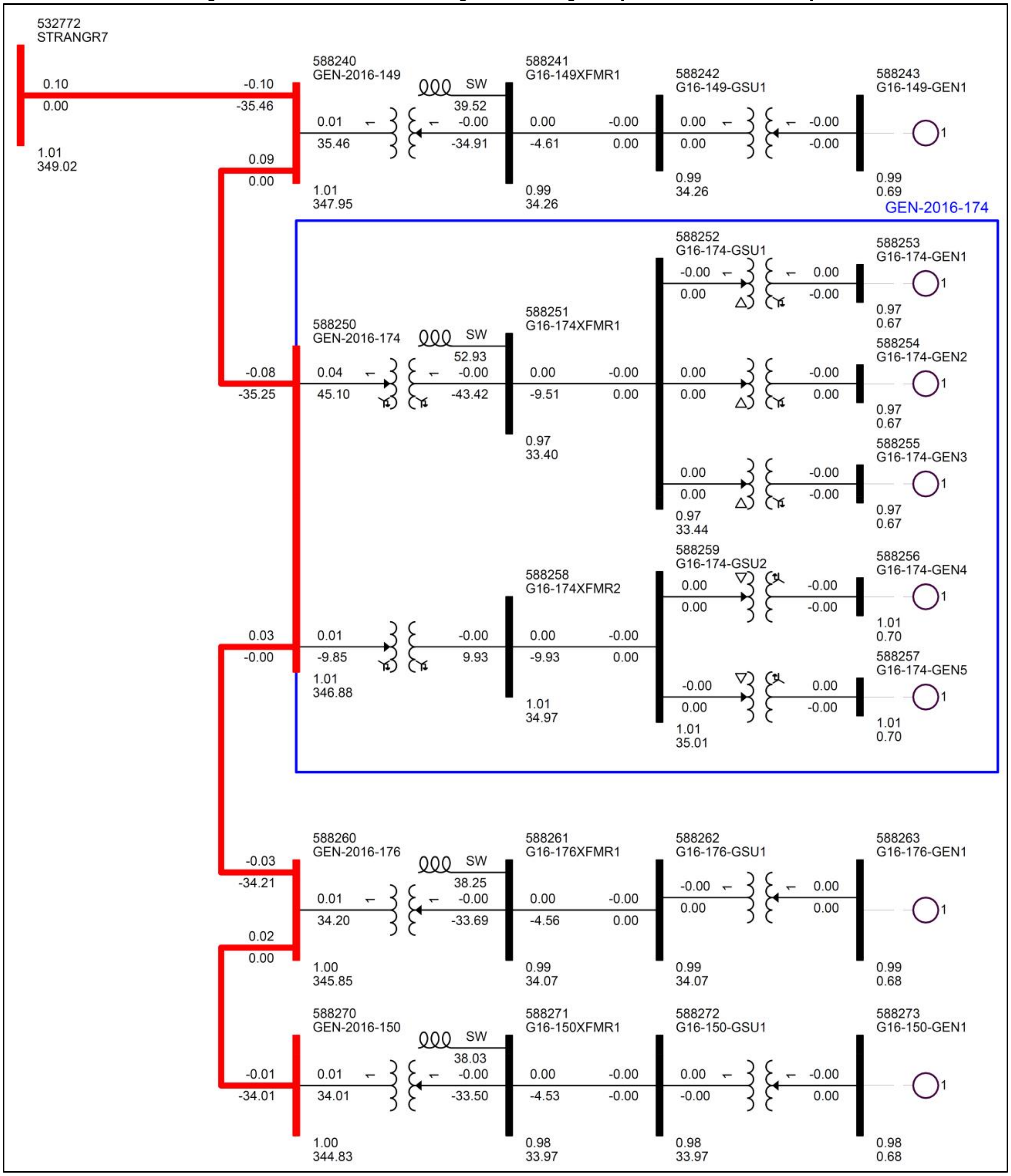


Figure 4-2: GEN-2016-174 Single Line Diagram (MRIS Shunt Reactor)



5.0 Short Circuit Analysis

A short-circuit study was performed using the 2018SP and 2026SP models for GEN-2016-174. The detail results of the short-circuit analysis are provided in Appendix C.

5.1 Methodology

The short-circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 345 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels with and without GEN-2016-174 online. GEN-2016-149, GEN-2016-176, and GEN-2016-150 were left online throughout the analysis.

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-2016-174 POI bus fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 26.78 kA.

The maximum fault current calculated within 5 buses with GEN-2016-174 was less than 57 kA for the 2018SP and 2026SP models. The maximum increase in fault current was about 23% and 1.14 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2018SP	26.30	26.78	0.48	1.8%
2026SP	26.30	26.78	0.48	1.8%

Table 5-2: 2018SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	13.0	-0.01	-0.1%
115	34.2	0.06	0.2%
161	54.3	0.00	0.0%
230	25.0	-0.01	0.0%
345	29.8	1.14	23.0%
Max	**54.3**	**1.14**	**23.0%**

Table 5-3: 2026SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	13.1	-0.01	-0.1%
115	34.2	0.06	0.2%
161	56.6	-0.01	0.0%
230	25.0	-0.01	0.0%
345	29.8	1.14	23.0%
Max	**56.6**	**1.14**	**23.0%**

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine configuration change and other modifications to the GEN-2016-174 project. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix D. 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 E.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested 59 x GE 2.3 MW (GEWTG2), 3 x GE 2.52 MW (GEWTG2), and 58 x GE 2.72 MW (GEWTG2) turbine configuration for the GEN-2016-174 generating facilities. This stability analysis was performed using PTI's PSS/E version 33.7 software.

The stability models were developed using the models from DISIS-2016-002 for Group 13. The modifications requested to project GEN-2016-174 were used to create modified stability models for this impact study.

The modified dynamics model data for the DISIS-2016-002 Group 13 request, GEN-2016-174, 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-2016-174 and other equally and prior queued projects in Group 13. In addition, voltages of five (5) buses away from the POI of GEN-2016-174 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 536 (WERE), 540 (GMO), 541 (KCPL), 542 (KACY), 544 (EMDE), 545 (INDN), 635 (MEC), 640 (NPPD), 645 (OPPD), 650 (LES), 652 (WAPA), 330 (AECI), and 356 (AMMO) 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-2016-174 and selected additional fault events for GEN-2016-174 as required. The new set of faults were simulated using the modified study models. The fault events included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers. The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 2017 Winter Peak, 2018 Summer Peak, and the 2026 Summer Peak models.

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT32-3PH	P1	3 phase fault on the STILWEL (542968) to W.GRDNR (542965) 345kV line circuit 1, near STILWEL. a. Apply fault at the STILWEL 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT33-3PH	P1	3 phase fault on the STILWEL (542968) to LACYGNE (542981) 345kV line circuit 1, near STILWEL. a. Apply fault at the STILWEL 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT35-3PH	P1	3 phase fault on the W.GRDNR (542965) to SWISVAL (532774) 345kV line circuit 1, near W.GRDNR. a. Apply fault at the W.GRDNR 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT36-3PH	P1	3 phase fault on the W.GRDNR (542965) to CRAIG (542977) 345kV line circuit 1, near W.GRDNR. a. Apply fault at the W.GRDNR 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT37-3PH	P1	3 phase fault on the W.GRDNR (542965) to LACYGNE (542981) 345kV line circuit 1, near W.GRDNR. a. Apply fault at the W.GRDNR 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT38-3PH	P1	3 phase fault on the W.GRDNR 345/161/13.8kV (542965/542966/543649) transformer circuit 11, near W.GRDNR. a. Apply fault at the W.GRDNR 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT48-3PH	P1	3 phase fault on the MORRIS (532770) to JEC N (532766) 345kV line circuit 1, near MORRIS. a. Apply fault at the MORRIS 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.
FLT50-3PH	P1	3 phase fault on the JEC N (532766) to HOYT (532765) 345kV line circuit 1, near JEC N. a. Apply fault at the JEC N 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.
FLT52-3PH	P1	3 phase fault on the JEC N 345/230/13.8kV (532766/532852/532805) transformer circuit 1, near JEC N. a. Apply fault at the JEC N 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT54-3PH	P1	3 phase fault on the HOYT (532765) to STRANGR (532772) 345kV line circuit 1, near HOYT. a. Apply fault at the HOYT 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT55-3PH	P1	3 phase fault on the HOYT 345/115/13.8kV (532765/533163/532804) transformer circuit 1, near HOYT. a. Apply fault at the HOYT 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT56-3PH	P1	3 phase fault on the STRANGR (532772) to 87TH (532775) 345kV line circuit 1, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT57-3PH	P1	3 phase fault on the STRANGR (532772) to IATAN (542982) 345kV line circuit 1, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT58-3PH	P1	3 phase fault on the STRANGR 345/115/14.4kV (532772/533268/532816) transformer circuit 1, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT59-3PH	P1	3 phase fault on the 87TH (532775) to CRAIG (542977) 345kV line circuit 1, near 87TH. a. Apply fault at the 87TH 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT60-3PH	P1	3 phase fault on the 87TH 345/115/13.8kV (532775/533283/532818) transformer circuit 1, near 87TH. a. Apply fault at the 87TH 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT61-3PH	P1	3 phase fault on the IATAN (542982) to EASTOWN (541400) 345kV line circuit 1, near IATAN. a. Apply fault at the IATAN 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT62-3PH	P1	3 phase fault on the IATAN (542982) to NASHUA (542980) 345kV line circuit 1, near IATAN. a. Apply fault at the IATAN 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT63-3PH	P1	3 phase fault on the IATAN 345/161/13.8kV (542982/541350/541150) transformer circuit 11, near IATAN. a. Apply fault at the IATAN 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT64-3PH	P1	3 phase fault on the EASTOWN (541400) to ST JOE (541199) 345kV line circuit 1, near EASTOWN. a. Apply fault at the EASTOWN 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT65-3PH	P1	3 phase fault on the EASTOWN 345/161/13.8kV (541400/541401/541402) transformer circuit 1, near EASTOWN. a. Apply fault at the EASTOWN 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT66-3PH	P1	3 phase fault on the NASHUA (542980) to ST JOE (541199) 345kV line circuit 1, near NASHUA. a. Apply fault at the NASHUA 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT67-3PH	P1	3 phase fault on the NASHUA (542980) to HAWTH (542972) 345kV line circuit 1, near NASHUA. a. Apply fault at the NASHUA 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT68-3PH	P1	3 phase fault on the NASHUA 345/161/13.8kV (542980/543028/543640) transformer circuit 11, near NASHUA. a. Apply fault at the NASHUA 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT76-3PH	P1	3 phase fault on the CRAIG 345/161/13.8kV (542977/542978/543641) transformer circuit 11, near CRAIG. a. Apply fault at the CRAIG 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT89-3PH	P1	3 phase fault on the JEC N (532766) to MORRIS (532770) 345kV line circuit 1, near JEC N a. Apply fault at JEC N 345kV bus. b. Clear fault after 3.6 cycles and trip the faulted line.
FLT85-SB	P4	W.GARDNR (542965) 345KV Stuck Breaker Scenario 1 a. Apply single line to ground fault at the W.GARDNR 345kV bus. b. Clear fault after 11 cycles c. Trip W.GARDNR (542965) – CRAIG (542977) 345kV line d. Trip W.GARDNR 345/161/13.8kV (542965/542966/543649) transformer
FLT86-SB	P4	W.GARDNR (542965) 345KV Stuck Breaker Scenario 2 a. Apply single line to ground fault at the W.GARDNR 345kV bus. b. Clear fault after 11 cycles c. Trip W.GARDNR (542965) – CRAIG (542977) 345kV line d. Trip W.GARDNR (542965) – SWISVAL (532774) 345kV line
FLT87-SB	P4	W.GARDNR (542965) 345KV Stuck Breaker Scenario 3 a. Apply single line to ground fault at the W.GARDNR 345kV bus. b. Clear fault after 11 cycles c. Trip W.GARDNR (542965) – STILWEL (542968) 345kV line d. Trip W.GARDNR (542965) – SWISVAL (532774) 345kV line
FLT88-SB	P4	STRANGR (532772) 345KV Stuck Breaker Scenario a. Apply single line to ground fault at the STRANGR 345kV bus. b. Run 4.6 cycles, then trip STRANGR (532772) TO IATAN (542982) 345kV line c. Run 10 cycles, then trip STRANGR (532772) – 87TH (532775) 345kV line d. Clear fault
FLT89-PO1	P6	**Prior outage of STRANGR (532772) to HOYT (532765) 345kV circuit 1 line** 3 phase fault on the JEC N (532766) to MORRIS (532770) 345kV line circuit 1, near JEC N a. Apply fault at JEC N 345kV bus. b. Clear fault after 3.6 cycles and trip the faulted line.
FLT9001-3PH	P1	3 phase fault on the STRANGR (532772) to HOYT (532765) 345kV line circuit 1, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on the IATAN 345/24kV (542982/542957) transformer, near IATAN. a. Apply fault at the IATAN 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip generator IAT G1 1 (542957)**
FLT9003-3PH	P1	3 phase fault on the HOYT (532765) to JEC N (532766) 345kV line circuit 1, near HOYT. a. Apply fault at the HOYT 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9004-3PH	P1	3 phase fault on the JEC N (532766) to SUMMIT (532773) 345kV line circuit 1, near JEC N a. Apply fault at JEC N 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on the JEC N 345/26kV (532766/532652) transformer, near JEC N. a. Apply fault at the JEC N 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer. **Trip generator JEC U2 (532652)**

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9006-3PH	P1	3 phase fault on the CRAIG (542977) to W.GRDNR (542965) 345kV line circuit 1, near CRAIG. a. Apply fault at the CRAIG 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9007-3PH	P1	3 phase fault on the JEC N (532766) to GEARY (532767) 345kV line circuit 1, near JEC N a. Apply fault at JEC N 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT56-PO1	P6	**Prior outage of the STRANGR (532772) to HOYT (532765) 345kV line circuit 1** 3 phase fault on the STRANGR (532772) to 87TH (532775) 345kV line circuit 1, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT57-PO1	P6	**Prior outage of the STRANGR (532772) to HOYT (532765) 345kV line circuit 1** 3 phase fault on the STRANGR (532772) to IATAN (542982) 345kV line circuit 1, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT58-PO1	P6	**Prior outage of the STRANGR (532772) to HOYT (532765) 345kV line circuit 1** 3 phase fault on the STRANGR 345/115/14.4kV (532772/533268/532816) transformer, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT56-PO2	P6	**Prior outage of the STRANGR (532772) to IATAN (542982) 345kV line circuit 2** 3 phase fault on the STRANGR (532772) to 87TH (532775) 345kV line circuit 1, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT57-PO2	P6	**Prior outage of the STRANGR (532772) to IATAN (542982) 345kV line circuit 2** 3 phase fault on the STRANGR (532772) to IATAN (542982) 345kV line circuit 1, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT58-PO2	P6	**Prior outage of the STRANGR (532772) to IATAN (542982) 345kV line circuit 2** 3 phase fault on the STRANGR 345/115/14.4kV (532772/533268/532816) transformer circuit 1, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9001-PO2	P6	**Prior outage of the STRANGR (532772) to IATAN (542982) 345kV line circuit 2** 3 phase fault on the STRANGR (532772) to HOYT (532765) 345kV line circuit 1, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT57-PO3	P6	**Prior outage of the STRANGR (532772) to 87TH (532775) 345kV line circuit 1** 3 phase fault on the STRANGR (532772) to IATAN (542982) 345kV line circuit 1, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT58-PO3	P6	**Prior outage of the STRANGR (532772) to 87TH (532775) 345kV line circuit 1** 3 phase fault on the STRANGR 345/115/14.4kV (532772/533268/532816) transformer circuit 1, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9001-PO3	P6	**Prior outage of the STRANGR (532772) to 87TH (532775) 345kV line circuit 1** 3 phase fault on the STRANGR (532772) to HOYT (532765) 345kV line circuit 1, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT56-PO4	P6	**Prior outage of the STRANGR 345/115/14.4kV (532772/533268/532811) transformer circuit 1** 3 phase fault on the STRANGR (532772) to 87TH (532775) 345kV line circuit 1, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT57-PO4	P6	**Prior outage of the STRANGR 345/115/14.4kV (532772/533268/532811) transformer circuit 1** 3 phase fault on the STRANGR (532772) to IATAN (542982) 345kV line circuit 1, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT58-PO4	P6	**Prior outage of the STRANGR 345/115/14.4kV (532772/533268/532811) transformer circuit 1** 3 phase fault on the STRANGR 345/115/14.4kV (532772/533268/532816) transformer circuit 1, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9001-PO4	P6	**Prior outage of the STRANGR 345/115/14.4kV (532772/533268/532811) transformer circuit 1** 3 phase fault on the STRANGR (532772) to HOYT (532765) 345kV line circuit 1, near STRANGR. a. Apply fault at the STRANGR 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT1001-SB	P4	**Stuck Breaker on the HOYT (532765) – STRANGR (532772) 345kV circuit 1 line** a. Apply single-phase fault at HOYT (532765) on the 345kV bus b. After 16 cycles, trip the HOYT (532765) to STRANGR (532772) 345kV line circuit 1 c. Trip the HOYT (532765) to JEC N (532766) 345kV circuit 1 line
FLT1002-SB	P4	**Stuck Breaker on the 87TH (532775) – STRANGR (532772) circuit 1 line** a. Apply single-phase fault at 87TH (532775) on the 345kV bus b. After 16 cycles, trip the 87TH (532775) to STRANGR (532772) line circuit 1 c. Trip the 87TH (532775) to CRAIG (542977) 345kV line circuit 1
FLT1003-SB	P4	**Stuck Breaker on the IATAN (542982) – NASHUA (542980) circuit 1 line** a. Apply single-phase fault at IATAN (542982) on the 345kV bus b. After 16 cycles, trip the IATAN (542982) – NASHUA (542980) circuit 1 line c. Trip the IATAN (542982) to EASTOWN (541400) 345kV line circuit 1
FLT1004-SB	P4	**Stuck Breaker on the STRANGR (532772) 345KV** a. Apply single-phase fault at the STRANGR 345kV bus. b. After 16 cycles, trip the STRANGR (532772) to HOYT (532765) 345kV line circuit 1 c. After 16 cycles, trip the STRANGR (532772) to 87TH (532775) 345kV line circuit 1
FLT1005-SB	P4	**Stuck Breaker on the STRANGR (532772) 345KV** a. Apply single-phase fault at the STRANGR 345kV bus. b. After 16 cycles, trip the STRANGR (532772) to HOYT (532765) 345kV line circuit 1 c. After 16 cycles, trip the STRANGR 345/115/14.4kV (532772/533268/532811) transformer circuit 1

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT1006-SB	P4	**Stuck Breaker on the STRANGR (532772) 345KV** a. Apply single-phase fault at the STRANGR 345kV bus. b. After 16 cycles, trip the STRANGR (532772) to IATAN7 (542982) 345kV line circuit 1 c. After 16 cycles, trip the STRANGR 345/115/14.4kV (532772/533268/532816) transformer circuit 1
FLT1007-SB	P4	**Stuck Breaker on the STRANGR 345/115/14.4kV (532772/533268/532811) transformer circuit 1** a. Apply single-phase fault at STRANGR3 (533268) on the 115kV bus b. After 16 cycles, trip the STRANGR 345/115/14.4kV (532772/533268/532811) transformer circuit 1 c. Trip the STRANGR3 (533268) to NW LEAV3 (533259) 115kV line circuit 1
FLT1008-SB	P4	**Stuck Breaker on the STRANGR 345/115/13.8kV (532772/533268/532816) transformer circuit 1** a. Apply single-phase fault at STRANGR3 (533268) on the 115kV bus b. After 16 cycles, trip the STRANGR 345/115/13.8kV (532772/533268/532816) transformer circuit 1 c. Trip the STRANGR3 (533268) to JARBALO3 (533244) 115kV line circuit 1

6.3 Results

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

Table 6-2: GEN-2016-174 Dynamic Stability Results

Fault ID	17WP			18SP			26SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT32-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT33-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT35-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT36-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT37-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT38-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT48-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT50-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT52-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT54-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT55-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT56-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT57-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT58-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT59-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT60-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT61-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT62-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT63-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT64-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT65-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT66-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT67-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT68-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT76-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	17WP			18SP			26SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT89-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT85-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT86-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT87-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT88-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable						
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
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
FLT56-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT57-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT58-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT89-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT56-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT57-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT58-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT57-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT58-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT56-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT57-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT58-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-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. A Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later Queue priority date.

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-2016-174 would not be negatively impacted and that no new upgrades are required due to the requested modification, thus not resulting in a material impact on the cost or timing of any Interconnection Request with a later Queue priority date.

8.0 Conclusions

The Interconnection Customer for GEN-2016-174 requested a Modification Request Impact Study to assess the impact of the turbine and facility changes to a configuration with a total of 59 x GE 2.3 MW + 3 x GE 2.52 MW + 58 x GE 2.72 MW wind turbines for total capacity of 301.02 MW. In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformers, and the generation interconnection line.

SPP determined that power flow should not be performed based on the POI injection decrease of 1.73%. However, SPP determined that a turbine parameter comparison and an impedance comparison should be performed to evaluate whether fault analysis and short-circuit analysis is appropriate.

The turbine changes were from GE turbines to GE turbines, but the modeling parameters of the dynamic stability models changed significantly. The modification request resulted in a change in the equivalent impedances from the point of interconnection to the generator step up transformers of approximately 23.5%. As such a dynamic stability analysis was deemed necessary and the scope of this modification request study was expanded from a charging current compensation analysis to include both short-circuit analysis and dynamic stability analysis.

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-2016-174 project needed 56.48 MVAr of reactor shunts on the 34.5 kV bus of the project substation, an increase from the 39.34 MVAr found in the pre-modification case. 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-2016-174 contribution to three-phase fault currents in the immediate systems at or near GEN-2016-174 was not greater than 1.14 kA for the 2018SP and 2026SP cases. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-174 generators online were below 57 kA for the 2018SP models and 2026SP models.

The dynamic stability analysis was performed using the three DISIS-2016-002 models 2017 Winter Peak, 2018 Summer Peak, 2026 Summer Peak. Up to 60 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

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

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

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.